STATE REVIEW OF OIL AND NATURAL GAS ENVIROMENTAL REGULATIONS (STRONGER)

2000

PART I: GENERAL - Underground Injection Control Program

A. Statutory authorities and regulatory jurisdictions

1. Please include a copy of all statutes, rules, regulations, policies and orders applicable to the management and disposal of Class II eligible wastes, abandoned oil, gas and service wells, enhanced recovery projects, oil field NORM (naturally occurring radioactive materials) if injected into wells and water produced in connection with the production of coal bed methane.

   Public Resources Code (PRC) – Attachment 1

   California Code of Regulations (CCR) – Attachment 2

   Manual of Instruction (MOI) – The MOI is too large a document to include as an attachment. However, it will be made available during the on-site review in Bakersfield.

2. What is the statutory authority upon which your UIC program is based?

   Section 3106, PRC

3. Does this statutory authority include promulgation of rules and regulations?

   Yes, Section 3013, PRC.

4. Do the statutes relating to oil and gas or statutes pertaining to the protection of "waters of the State" contain definitions of injection, enhanced oil recovery, disposal, types of wells, hydraulic fracturing, fresh and/or usable water, and USDWs (Underground Sources of Drinking Water)?

   Yes, however, specifics to the UIC program are contained in regulation, Sections 1724.6 – 1724.10, CCR.

5. Do the statutes mandate or allow the establishment of advisory boards, regulation review boards, or other mandated vehicles designed to bring UIC program stakeholders together? If not mandated by statute, are other policies or orders issued by the agency, which brings such groups together.

   No. The Office of Administrative Law (OAL) is responsible for reviewing administrative regulations proposed by State agencies for compliance with standards set forth in California's Administrative Procedure Act, for transmitting these regulations to the Secretary of State, and for publishing

regulations in the California Code of Regulations for public review. Prior to submitting proposed regulations to OAL, the Division of Oil, Gas, and Geothermal Resources (Division) submits them to the industry's advocacy groups for review and comment. Although not related directly to the UIC program, the Division, BLM, and industry representatives formed a workgroup to review and develop statutes and regulations, as well as provide periodic updates on pertinent issues.

When field rules are changed, the Division works in partnership with the operator(s) and other agencies to develop a field rule to address a specific situation unique to that field (Section 1722(k), CCR).

6. Please provide a brief (three pages or less) historical overview of the evolution of the UIC program in your state. This should include the evolution of statutes, oil and gas production history, geology and hydrogeology, changes in agency jurisdiction, institution of injection practices and the trend of injection wells through time. Geologic maps and tables of trends are acceptable *in lieu* of rhetoric.

The California petroleum industry began in the 1870s. The Division of Oil, Gas, and Geothermal Resources (Division) was formed in 1915 to address the needs of the State, local governments, and industry by establishing statewide uniform laws and regulations. The Division supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells, preventing damage to: (1) life, health, property, and natural resources; (2) underground and surface waters suitable for irrigation or domestic use; and (3) oil, gas, and geothermal deposits. Division requirements encourage wise development of California's oil, gas, and geothermal resources while protecting the environment.

The Division's programs include: well permitting and testing; safety inspections; oversight of production and injection projects; environmental lease inspections; idle-well testing; inspecting oilfield tanks, pipelines, and sumps; contracting for hazardous and orphaned well plugging and abandonment operations; and subsidence monitoring.

To date, about 180,000 oil, gas, and geothermal wells have been drilled in California and about 88,000 are still in use. About 3,000 new wells were drilled in the State ***in 2000. Daily oil production runs about 855,000 barrels, placing California fourth among oil producing states. The estimated reserve is about 3.6 billion barrels of recoverable crude oil and can be found in eleven sedimentary basins. The majority of the*** State***'s oil and gas production occurs in the San Joaquin Basin. In fact, if Kern County (within the San Joaquin***

Basin) were a country, it would rank 25th in world in oil production for the year 2000.

About 55 percent of all oil produced in California results from injecting steam, water or gas into oil reservoirs. Since injection operations began in California in the 1940s, more than 70 billion barrels of produced water have been injected into oil and gas zones and other nonpotable aquifers without causing any known degradation of fresh waters.

Although the Division was created in 1915, regulations for oil and gas operations, including injection operations, were not adopted until 1974.

In 1983, the Division was granted primary responsibility and authority (primacy) from the Environmental Protection Agency under the provisions of the Safe Drinking Water Act. Although the Division had been regulating injection wells since the 1940s, the grant of primacy necessitated an augmentation of the existing program. This included:

- *Extension of the existing program to include the protection of subsurface waters ranging from 3,000 ppm TDS to 10,000 ppm TDS.*
- *Increased field-testing, inspection, monitoring, surveillance, and sampling to ensure mechanical integrity and the proper operation of wells.*
- *Quarterly and annual reporting covering permitting, compliance evaluation, and well testing.*
- *Increased responsibilities regarding the public's participation in injection project decisions.*
- *Consultation with other agencies and local governments regarding project proposals and modifications.*
- *Gathering and presenting engineering and geologic information for determining whether aquifers may be used for injection purposes (aquifer exemptions).*

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years.

B. Program coordination

1. Attach an agency organizational chart and identify UIC positions in permitting and file review, inspections, mechanical integrity testing, compliance and enforcement, data management and public outreach.

   Organization Chart: Attachment 4.

The Division's public outreach program is designed to inform interested citizens about the program as a whole and to alert them about proposed project applications for injection wells and well modifications in their areas. Videotape, UIC information pamphlet, and other media have been created as public educational and information material. In addition, Division staff visits K-12 schools frequently to make presentations about oil, gas, and underground injection operations in the State.

The Division's web page www.conservation.ca.gov provides information on its programs, production and injection statistics, maps, publications, reports, and other information useful to the public.

2. Discuss the mechanisms in place in your state for the coordination of UIC activities and environmental protection programs, complaint and emergency response among the public, government agencies and the regulated industry.

The Division has a comprehensive memorandum of agreement (MOA) with the State Water Resources Control Board (SWRCB) (Attachment 5). This MOA outlines the procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. These procedures are intended to provide a coordinated approach that results in a single permit that satisfies the statutory obligations of both parties. The procedures ensure that construction or operation of oil, gas, and geothermal injection wells and surface disposal of wastewater from oil, gas, and geothermal production does not cause degradation of waters of the State of California.

Also, the Division has an MOA (Attachment 6) with the U.S. Environmental Protection Agency (EPA) that establishes the responsibilities and procedures used by the Division (which has primary authority) and the EPA in the administration of the UIC program. The federal UIC program corresponds closely with the Division's long-standing program of injection-project surveillance.

Complaints and emergencies for Class II wells are essentially nonexistent. If a complaint or emergency response were received, it would be directed to the appropriate district office where an engineer would complete a Report of Occurrence (Attachment 13) form. The form includes details of the emergency or complaint, location, type, volume (if spill), if the emergency situation is under control, name of person making the call, a contact person, etc. All complaints will be investigated and appropriate action taken when it is justified. Every effort will be made to resolve a valid problem and satisfy a complainant, or a complainant will be informed why a matter is not within our jurisdiction, if that is the case. The operator is notified of the complaint or emergency and the citizen who made the

complaint receives notification from the Division concerning the results of the investigation.

Complaints are classified as informal or formal:

Informal complaints are usually made by telephone or in person. When an informal complaint is received, the Division will:

- ξ ***Investigate to determine the validity of the complaint.***
- ξ ***Attempt to settle the difference between the parties involved.***

Formal complaints must be in writing and are covered by two, separate oil and gas statutes and one geothermal statute. Section 3235, PRC, provides for a complaint to the Supervisor by a person owning land or operating wells within a radius of one mile of a well or wells complained against. Section 3302, PRC, provides for a complaint to the Director of the Department of Conservation by any person operating in any oil field where an unreasonable waste of gas in any field or fields is occurring. These sections also provide that the Supervisor may initiate an investigation of wells or request a public hearing on gas wastage.

Section 3753, PRC, provides for a complaint to the supervisor or to the District Deputy, by any person, concerning possible damage by a geothermal well.

Compliance with the California Environmental Quality Act (CEQA) is a routine element in the project permitting process. The Division can approve a UIC project plan, but not the drilling of wells until CEQA requirements are met. The CEQA lead agency is usually the local agency. This agency may prepare an environmental impact report, including recommendations to mitigate impacts the project may have on the environments. As an alternative, they may prepare a declaration that the project will not cause an adverse impact on the environment. Public concerns are often addressed through these means.

3. Describe briefly the nature of the agency (Commission, Board, Appointed Head etc.) and further discuss the relationship of the oil and gas authority to the agency leadership.

The Division supervises the drilling, operation, maintenance, and plugging and abandonment of oil, gas, and geothermal wells in California. It also oversees the operation, maintenance and removal or abandonment of facilities attendant to these wells and their surrounding property. Through the enforcement of regulations, the Division encourages sound engineering practices and prudent development of hydrocarbon and geothermal resources. The Division's key customers are oil, gas, and geothermal operators; private consultants and drilling

engineers; State and federal agencies; local and regional governmental agencies; and public interest and environmental groups.

C. Staffing and funding

1. Please provide funding levels and the total staff complement for the agency or division of agency (if applicable) for the period FY 1998 to present. Please differentiate between UIC and non-UIC program funding and staffing levels. Assume fractional FTEs for staff who perform both UIC and non-UIC functions.

The chief of the Division is the State Oil and Gas Supervisor. The Division has 130 employees, including 65 professional geologists and petroleum engineers.

Although there are assigned engineers who are tasked solely with performing UIC related tasks, all engineers and most clerical staff support the UIC program, although the percentage of support will vary. The Division's UIC program is decentralized. The Headquarters office is located in Sacramento and there are six district offices located strategic to oil and gas fields. Permitting, file review, and most compliance and enforcement functions take place at the district office level. Sacramento handles the overall administrative program functions, including grant application, grant monitoring, record keeping, general data management, reporting, and program oversight and policy development (Attachment 7).

		TOTAL	TOTAL UIC	TOTAL Oil & Gas
98-99	Salaries & Benefits	$864,195.91	$194,089.76	$670,106.15
	O,E,&E	$7,692,975.59	$1,727,765.39	$5,965,210.20
	Overhead	$1,327,539.28	$298,152.05	$1,029,387.23
	TOTAL	$9,884,710.78	$2,220,007.19	$7,664,703.59
99-00	Salaries & Benefits	$7,039,310.49	$1,580,958.74	$5,458,351.75
	O,E,&E	$2,441,809.31	$548,405.95	$1,893,403.36
	Overhead	$1,300,922.61	$292,174.21	$1,008,748.40
	TOTAL	$10,782,042.41	$2,421,538.90	$8,360,503.51
00-01	Salaries & Benefits	$6,225,153.78	$1,398,107.29	$4,827,046.49
	O,E,&E	$3,058,070.80	$686,812.12	$2,371,258.68
	Overhead	$1,225,372.78	$275,206.47	$950,166.31
	TOTAL	$10,508,597.36	$2,360,125.88	$8,148,471.48
01-02	Salaries & Benefits	$3,789,571.32	$851,099.82	$2,938,471.50
(6 months)	O,E,&E	$789,911.81	$177,406.29	$612,505.52
	Overhead	$615,853.85	$138,314.62	$477,539.23

TOTAL	$5,195,336.98	$1,166,820.73	$4,028,516.25

2. Are the levels of funding and staff provided adequate for full UIC program implementation? Please discuss in reference to the trends shown in C-1.

The Division receives an annual grant allocation from the EPA to support the UIC program. In the Primacy Award granted to the Division in 1983, a Cooperative Agreement was established that identifies the non-federal and federal participation (in funds) required between the Primacy State (recipient) and EPA. The Cooperative Agreement between the Division and the EPA established a cost share agreement set at 25 percent state (recipient) and 75 percent federal. To date, the Division has contributed over 80 percent of the funding necessary to conduct California's UIC Program. The bulk of the UIC funding comes from the Division's oil and gas assessment.

D. Data management program for agency

Describe in either flow chart form or by general description how the UIC data management system fits into the agency system, the state data base shared by other agencies having responsibility for oil, gas, water allocation and protection, and water planning for the state. Also describe the linkage that exists with any state GIS system or system affording Global Positioning capability.

The Division requires operators to file monthly reports (electronic or hardcopy) on well production and/or injection that are entered into the data management system (WellStat). About 90 percent of the monthly injection data from operators is received in an electronic format. Available information includes a list of all active injection wells, idle wells, volume injected, pressure, days injecting, shut in, and the source of fluid (production records provide the amount of fluid and disposition). The information is posted monthly on the Division's web page and printed in the Annual Report (Attachment 8).

All wells are being plotted digitally on Division maps using latitude/longitude well locations provided by the operator or by well locations arrived at by the Division using the heads-up display or GPS. Over 90 percent of all wells have been converted to a digitized location. Each well location will be tied to the WellStat database to allow web access to well production and injection information.

E. Interagency coordination

1. Please provide or summarize any memoranda of agreements or similar agreements between state agencies, or between the state and any other governmental entities (BLM, US Fish and Wildlife Service, EPA, Indian Tribes, local jurisdictions and

water management districts) which relate to UIC regulation, oil and gas waste, sharing of information, or processing of complaints.

The Division has an MOA with the SWRCB, whereby the permitting of surface wastewater disposal is regulated by SWRCB and the Division regulates any underground injection of wastewater or other fluids associated with oil and gas production (Attachment 9). Also, the Division has an MOA with the EPA regarding public notification and aquifer exemptions (Attachment 10). Furthermore, the Division has an MOA with the Bureau of Land Management (BLM) to delineate procedures for regulation oilfield operations, including UIC activities, where both the BLM and the Division have jurisdictional authority (Attachment 11).

2. Provide a flow chart, organizational diagram or other document which shows how your oil and gas program (agency) fits into the state picture with other agencies or entities having authority over portions of oil and gas regulation, oil related environmental protection, or regulation of water use and state water planning.

Attachment 12

F. Changes in general activities since 1990

1. Excluding the changes in data management that are to be described in Section I-D and throughout the remaining sections, what significant changes have occurred within the agency or outside the agency that have affected the administration of the UIC program? New statutes or major regulatory changes?

In 1996, Section 1724.10(j)(1), CCR, was added to include mechanical integrity testing of the casing-tubing annulus every five years.

2. Has the Congressional passage of the Safe Drinking Water Act Reauthorization (1996) and other Federal mandates caused changes in the way the UIC program is administered (i.e. Wellhead protection, Source Water Protection, Watershed Management etc.)?

Division – No.

3. Has the SARA Title III Program of EPA and the Community Right -to Know Program (EPCRA) had an impact on your UIC program? On the ability of the regulated community to meet deadlines established in the State UIC regulations? If so, describe the impact.

Division – No.

PART II: PERMITTING/FILE REVIEW

A. OBJECTIVE: Understand the application flow process in the state.

1. How does the Operator initiate a permit application?

   The operator files a complete project plan and/or well permit application with the appropriate district office.

   The Division requires that an operator submit a complete project plan that includes a geologic and engineering study; an injection plan, and other data listed in Section 1724.7, CCR, for onshore projects and 1748.2, CCR, for offshore projects. Requirements and surveillance procedures for injection projects are designed to ensure the injected fluid is confined to the approved zone of injection and that adjoining operations will not be affected adversely. The condition of all wells within a finite area, known as the Area of Review (AOR), is reviewed to ensure the protection of all oil and gas zones and USDWs. A thorough knowledge of the stratigraphy and subsurface conditions in the project area is essential prior to final project approval.

   Once the injection project is approved, the operator may submit an individual injection well permit applications. The application may be a permit to drill a new well or convert an existing oil and gas well to injection.

2. Who receives the application from the Operator?

   An Associate Oil and Gas Engineer in the appropriate district office receives the project or well application.

3. How and by whom are permit applications screened for completeness?

   The district Associate Oil and Gas Engineer responsible for permitting reviews the project or well application and ensures that all the required information has been submitted.

4. What is the procedure used when an application is found to be incomplete?

   The operator is notified of the deficiencies and is informed that the information must be submitted before the project can be approved. Review and evaluation by Division engineers might continue; however, the extent of the evaluation would depend upon the type of information that is available to the engineers.

5. How long is the Operator given to reply in the case of incomplete applications before they are considered null and void and how is the Operator notified?

   Each district office maintains a tickler file; however, once a letter requesting additional information is sent to the operator, no other formal follow-up occurs. It is incumbent upon the operator to complete the project or well application.

6. In the case of voided applications, is the application returned to the Operator or kept by the reviewing agency?

   The project or well application may be returned to the operator immediately if significant information is not included in the application. If the application is retained and a request for additional information was sent to the operator, there is no set time for return if the operator does not reply. It is the prerogative of the district office.

7. Upon a determination of application completeness, how is it routed and concurred upon?

   Once the permitting engineer prepares a project permit or well permit, it is reviewed by the Senior Engineer in charge of technical projects (the District Deputy in the smaller districts) and signed and approved by the District Deputy.

8. Who are the individuals responsible for reviewing the different aspects of the permit application? Technical Issues? Administrative Issues?

   Technical - ***The permitting engineer is responsible for reviewing the complete project application. In larger districts, the application is routed to the engineers with expertise in the geology or reservoir characteristics of the project area.***

   Administrative - ***A district engineer handles environmental compliance (CEQA), with support from Headquarters staff.***

9. What are the professional qualifications required for agency personnel reviewing a permit application?

   The permitting engineer is an Associate Oil and Gas Engineer that has (at least) a Bachelor's degree in geology or petroleum engineering. The permit is signed and approved by the District Deputy who is a Senior Oil and Gas Engineer in one of the four smaller district offices or a Supervising Oil and Gas Engineer in one of the two larger district offices.

10. How is an application tracked to ensure that both review and permit issuance/denial recommendation occurs in a timely manner?

    Each district has its own system for tracking injection permits; however, most use the computer. The Division is mandated, via Sections 3203 and 3229, PRC, to respond to each well permit within 10 working days from the date of receipt.

11. Is the process described under questions 1-10 the same or different for amendments applications to existing permits? (Existing in the sense the permit for which amendment is sought is active.) Is the process flow different for major versus minor amendments?

    The same process is used.

12. How are UIC well applications at commercial facilities handled?

    Commercial facilities undergo the same project review process as all injection projects. Individual permits are issued for each well. However, permit requirements are more stringent, requiring more fluid sample analyses and reporting (especially where fluids are trucked to the injection well(s)), manned or locked gates, and the retention of trucking manifests. An important difference is that a $50,000 life-of-the-well bond must be posted for each well, unless the operator has submitted at least a $250,000 blanket bond.

13. How are the official copies of the permits stored and protected from loss?

    A copy of each well record is on file in the district office and a duplicate copy is kept in offsite storage. Copies of all well records are also kept on microfilm that is maintained in each district office.

14. Does the State allow a well to be used for the disposal of both Class I and Class II fluids? Under what circumstances? How are these wells permitted and which agency acts as the principle in holding hearings?

    No.

B. Objective: Understand the current file review process.

1. What is the file review strategy? (i.e.) How are wells selected for file review)? Is the compliance history a factor of selection?

   A well is reviewed every time a mechanical integrity test (MIT) is performed on the well, or when the operator submits a rework notice. MITs are performed on

water-disposal wells at least once each year; waterflood wells once every two years; and steamflood wells every five years.

In addition, each injection project is reviewed with the operator annually. During the annual reviews, the entire project, including all wells within the project boundary are reviewed for compliance with permit conditions and project performance.

2. Who performs the file review and what are the qualifications of the reviewers?

   Any Division engineer can perform a file review. MITs are witnessed and approved by a field engineer. MIT results are reviewed and approved by an Associate Oil and Gas Engineer, who is in charge of UIC, who must have a Bachelor's degree in geology or petroleum engineering, with at least 2 years experience in the field.

   The Associate Engineer is also responsible evaluation and approval of rework notices and performs the annual project review with the operator.

3. Over a year period, what percentage of total UIC permits receives a file review?

   Approximately 80 percent.

4. How is the quality of file review assured and subsequently documented?

   Operating data and mechanical condition of a well are compared with permit conditions. File reviews are then documented on a database.

5. Where deficiencies are recovered during the review, what actions are taken to correct the deficiency?

   In the event a project review results in the determination that the enhanced recovery project is not fulfilling its intended purpose, project approval can be rescinded. However, this is usually an operator decision.

   Falsification of information by the operator or an operator's failure to comply with permit requirements can result in a fine and/or rescission of permit approval.

   The Division can order repair or remedial work on a well, with a deadline for compliance.

   The Division can revise permit requirements to update conditions of the project.

6. How long does it take to do an average file review of a well without complications? What are complications?

Initial reviews can take 2-3 hours because it would entail preparing a complete casing diagram from detailed analysis of all well histories.

Subsequent reviews (i.e., MITs, changes of casing diagram due to rework or remedial work, etc.) can take 15-30 minutes.

7. Assuming that file reviews are currently conducted on wells under permit, what action is taken toward the continued use of the well for injection while the deficiency is being corrected by the Operator? For technical deficiencies? For administrative or paper deficiencies?

See response to question 5.

C. OBJECTIVE: Understand the technical review and related aspects of the permit/file review process.

1. What are considered to be adequate casing and cementing (surface and production, etc.) requirements for a newly drilled injection well (depth, thickness, material, etc.)? Is casing set and cemented through all USDWs? If not, how are USDWs otherwise protected?

Sections 1722.2 – 1722.4, CCR cite casing and cement requirements for wells.

<u>Surface casing</u> – Set at a depth of a least 10 percent of total depth with a minimum of 200' and maximum of 1,500' of casing. The casing is cemented from the casing shoe to the surface and is set into a competent bed (2nd string is required if the first string is not set into a competent bed).

<u>Intermediate casing</u> – May be required to protect oil, gas, or freshwater zones, and to seal off lost circulation or anomalous pressure zones. Casing is cemented so that all freshwater zones, oil or gas zones, and anomalous pressure intervals are covered or isolated.

<u>Production casing</u> – If the casing does not extend to the surface, then there must be at least 100' of overlap with the next larger casing. The overlap must be cemented and a fluid entry test run.

2. What are considered to be adequate casing and cementing requirements for converted wells? Is casing required to be set and cemented through all USDWs? If not, how are the wells protected?

See response to question 2. Casing and cement requirements are the same for all wells (i.e., oil, gas, and injection).

Cement behind casing is not required across a USDW. There must be cement behind casing through the injection interval and 500' above the injection interval and 100' above the 3,000 mgl TDS interface. However, all intervals behind casing not filled with cement must be filled with mud. Division requirements comply with EPA standards that require wells be cased and cemented to prevent movement of fluids into USDWs.

3. Packer/ tubular goods requirements:

   a. Are packers routinely required for all newly completed and converted wells? If there are exceptions, what are the criteria used? Does an exception impose alternative requirements (i.e., more frequent MITs, annulus and pressure monitoring, limitation on injection volume)?

      Yes, see Section 1724.10(g), CCR.

      Exceptions may be made when there is:
      (1) No evidence of freshwater-bearing strata.
      (2) More than one string of casing cemented below the base of fresh water.
      (3) Other justification, as determined by the District Deputy, based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.

   b. Do permits specify the type or packer to be used?

      No.

   c. Do permits specify the use of tubing? Is lined tubing acceptable and under what conditions?

      Yes, see Section 1724.10(g), CCR. The regulations do not address lined tubing specifically; however, it is not prohibited. In areas where corrosion occurs, operators have used fiberglass tubing.

   d. Does the agency prescribe or impose restrictions on weight, grade, material, internal coating or other packer/tubing qualities?

      No, but casing and tubing must be of sufficient weight and grade, etc., to withstand collapse, burst, and tension forces (Section 1722.2, CCR).

4. Are dual completions accepted? What types?

Yes. Virtually any combination. Currently, we have dual injectors (SF/WF), dual producer/injector (OG/WF, OG/SF, OG/WD), and dual producers (two different zones). However, each dual completion is evaluated on a case-by-case basis to establish methods and conditions to protect useable waters.

5. How are the locations of USDWs determined? How often is the maps, charts or other information used for determination updated and by whom?

Most freshwater aquifers (3,000 mgl TDS or less) are known through years of permitting production wells and from in-house mapping of freshwater areas.

Historically, location of useable waters has been determined by using water analyses, E-log data, drilling records, and published geologic and reservoir reports on every oil/gas field in California.

6. How is the adequacy of the confining system determined? In those areas where confining geological deposits may consist of prominently incised channel sand fills or karst surfaces faults or other unique geologic conditions that may affect the containment of injected fluids, what buffer or insurance is provided to compensate for irregularities? How are such conditions evaluated?

Because most oil and gas fields in California have been under production for a long time, the Division has collected an abundance of information on the geology and reservoir characteristics of these fields. Much of the information available has been analyzed and interpreted into reports that are published by the Division.

Operators are required to submit data (i.e., E-logs, dipmeters, mud logs, sidewall sample logs, drilling surveys, etc.) that are used to determine zone characteristics and boundaries.

7. What types of monitoring systems are required or have been approved (flow rate and cumulative volumes, tubing pressure, annuli pressures, etc.)?

The monitoring of injection pressure and volumes is required for all injection wells. Monthly injection reports are required to be submitted to the Division.

Other monitoring systems may be required, such as graphs of time vs. injection rates or time vs. pressure, observation wells, and isobaric maps (Section 1724.10(k), CCR). In addition, periodic field inspections are made to check on surface pressures and conditions.

8. Has the compatibility of injectant/cement and injectant/formation fluid been a problem?

   No.

9. How are the maximum injection pressures and rates established?

   A step-rate test is performed to determine the fracture gradient (Section 1724.10(i), CCR)). The maximum allowable surface injection pressure would then be less than the fracture pressure.

   A step-rate test may be waived if the proposed injection pressure is considerably below the established pressure required to fracture the zone. The Division's injection manual lists established fracture gradients for different areas in California.

10. How is corrective action handled in those cases where the approval of the application is contingent upon resolution of an adverse situation?

    Before injection can commence, the conditional permit approval letter would require that all wells within the injection project area that need repair work or plugging be repaired or plugged to the satisfaction of the District Deputy.

    If a well requires corrective action after injection has commenced, an informal request by phone is made with a time limit for correction, depending on the severity of the problem. A follow-up letter is sent to indicate the specific problem that needs correction. Failure to comply with the written request results in the issuance of a formal order, possible fines imposed for noncompliance, and/or recession of injection approval.

D. OBJECTIVE: To understand the Area of Review considerations and procedures.

1. How is the Area of Review determined for enhanced recovery wells or projects? For salt-water disposal wells? For commercial wells?

   The Division uses the ¼-mile radius for area of review.

2. If area permits are issued, how is their area of review determined?

   N/A

3. In a case where the Operator elects to withdraw the application rather than take corrective action measures, what is the subsequent course of action taken by the agency?

No action is taken; the permit or project application is canceled.

4. What authorities are open to the State where the Area of Review reveals a problem (unplugged wells or other USDW threatening situation) that is on acreage outside the Operator's control? Is the Operator's application denied if he/she has no legal status to effect corrective action?

   Application approval could be denied if some form of action cannot be implemented.

E. OBJECTIVE: Understand the administrative permit application components.

1. Prior to permit issuance, what is the public notification for applications before the agency?

   When a project application is received, a notice of receipt of application to inject/dispose of water into a specific zone is published in a local newspaper of general circulation for 3 days. The public review and comment period is 15 days. A 15-day extension can be granted if requested by the public. If there are problems that cannot be resolved through direct communication with concerned persons, the Supervisor may schedule a public hearing. All public comments at the hearing are responded to.

2. When does the public comment period start? Upon determination of completeness or after completion of technical review?

   The public comment period begins the day the notice first appears in the newspaper. The project is not announced publicly until the Division has conducted a technical review and all Division requirements have been met.

3. When and where is public hearing opportunity held on an application?

   At the discretion of the State Oil and Gas Supervisor, public hearings may be scheduled upon request of concerned persons. The notice for a public hearing is published in a local paper 30 days prior to the hearing.

4. How are the public hearings conducted (formal, informal, transcript, qualifications etc.)?

   Formal hearings are conducted with a hearing officer (usually the State Oil and Gas Supervisor) and a public recorder (optional). A recording and/or a transcript of the hearing are made and all comments are responded to, in writing, within 30 days following the hearing.

5. What criteria, conditions or circumstances would prompt a public hearing on an application?

It is the intent of the State Oil and Gas Supervisor to schedule a public hearing whenever it is requested. There is no formal set of criteria that would guide a decision whether a hearing should be held. The main intent is to let the public voice their concerns. Typically, public hearings are scheduled whenever direct communication with a person does not answer their concerns, or if a hearing is requested, as long as concerns are related sufficiently to the project.

6. In reference to hearing participation, does the agency have a definition for "significant interest" below which level the permit would automatically be issued after notification?

No, it is left to the discretion of the State Oil and Gas Supervisor.

7. How often have public comments modified the conditions of the final permit?

Very rarely are public comments received.

8. What types of financial assurance mechanisms are used in connection with UIC applications? If used, how is the adequate coverage per well determined?

Operators are required to file cash or indemnity bonds to cover drilling, redrilling, deepening, or operations permanently altering casing. Bond amounts are determined by drill depth of the well. Also, surety companies must be authorized to do business in California (Sections 3204-3206, PRC).

Wells less than 5,000' deep	***-***	***$15,000***
Wells 5,000' – 9,999' deep	***-***	***$20,000***
Wells 10,000' or deeper	***-***	***$30,000***

In addition, each commercial production-water disposal well must be covered with a $50,000 life-of-the-well bond unless the operator has submitted at least a $250,000 blanket bond (Section 3205.2, PRC).

9. In reference to question #8, what conditions is blanket surety coverage allowed?

Section 3205, PRC allows any operator who drills, redrills, deepens, or alters the casing or one or more wells to submit a blanket bond.

Operators with less than 50 wells	***-***	***$100,000***
Operators with 50 or more wells	***-***	***$250,000***

Or, an operator may post a $1,000,000 blanket bond to cover all wells, including commercial disposal and idle wells.

10. How are complaints related to the proposed permit or application recorded and filed? Is the same filing process used for complaints, which are submitted to the agency after UIC approval has been given?

Complaints relative to proposed permits are rare because the Division addresses and responds to concerns through the public participation process prior to the issuance of permits. If a complaint were received, it would be placed in files that relate to the specific project, well, and/or in "subject" files.

F. OBJECTIVE: Understand the process for aquifer exemptions

1. How many exemptions have been requested since the inception for the program and what criteria were used for the request?

Aquifer exemptions were listed and included in the primacy application with EPA. Essentially, the list includes all hydrocarbon-bearing zones and nonhydrocarbon zones that were being injected into at the time of the primacy application. Prior to primacy, all injection zones (hydrocarbon and nonhydrocarbon bearing) had been reviewed previously for injection through the same injection project review as now. A public notice was issued on all aquifers exempted on the primacy application.

2. How many requests have been granted/denied and, if denied, what basis or reason was given? Who issued the denial?

Two.

3. Are minor aquifer exemptions granted? How many have been granted/denied?

No.

4. Are certain aquifers granted exemptions in some parts of the State while the SAME aquifer is considered non-exempt in other parts of the State? If so, what criteria are used?

No.

G. Objective: To understand the Data Management Systems Used in Review

Describe the data management system (s) used in the various components of the Permitting/File Review process as set forth in Section A-F. The description should delineate both the systems used for technical and administrative activities.

Currently, the Division is developing a Division wide Microsoft Access database that will include the unique components each district may use. This database will replace each database developed by individual districts.

The Division's WellStat is used to manage monthly reports submitted by operators. The information includes, injection volumes, pressures, days injecting, type of fluid injection, and fluid source. The Division can check for excessive injection pressures, periods of inactivity, injection volume, etc. The oil and gas program and the UIC program use WellStat for oversight.

1. When were the data management systems currently in use first put into operation?

   The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet their needs.

   In addition, production and injection data from 1977 is stored electronically.

2. Are these systems effective and efficient for the type of data management use?

   Yes. As these systems evolved over the years, they became more effective and efficient as additional functions were added. As an example, the information entered by field engineers allows UIC wells to be tracked electronically to ensure scheduled MITs are conducted and injection pressures are below the MASP, to populate reports, and to track other deficiencies.

3. What are the limitations in terms of addressing the basic regulatory needs?

   The most obvious limitation would be entering the data electronically. Historically, the Division has tracked the same information that is now being stored electronically, and in some cases hardcopy information is sufficient. However, providing this information in an electronic format vastly improves how this information is managed and used by the Division, operators, and public.

   Currently, the Division is beta testing a program that allows engineers to electronically enter data collected in the field using handheld computers. The information would then be synced to the office database.

4. Is there capability for the Operators to file some or all documentation pertaining to application submission electronically? Describe what electronic communication is currently available to the regulated community and the public.

   The Division's electronic permitting system (ePermit) is in the final stages of beta testing. Once operational, ePermit will allow operators to submit single or batch well-permit applications and receive a Division response (either a permit or denial letter) via the Internet. Lease maps, well diagrams, etc. can be added to the electronic permit application; however, notarized bond documents still will have to be submitted as hardcopy.

5. Is the agency's data management system locally (intramural) conceived or linked with other state databases?

   Although the Division's networked database is not linked to other State agencies; it is posted on the Division web site and can be accessed by the public or other agencies.

H. Changes and Modifications to Program Since 1990

Exclusive of the changes in data management described under Section G., what statutory, regulatory or policy changes have occurred during the past ten years in the UIC Permitting/File Review process? Please list or explain.

None.

PART III: INSPECTIONS

A. Objective: Understand how field operations are conducted and managed by the agency.

1. Are inspectors State employees or are they contractors?

   Full-time Division employees.

2. Do inspectors work out of an office, their homes, or other setting? Who coordinates the work of the inspectors and at level does this supervision take place (central office, district office, field supervisor working out of home)?

   The Division is configured with a Headquarters office located in Sacramento and six district offices located throughout the State and strategic to oil and gas fields. Permitting, file review, and most compliance and enforcement functions

take place at the district office level. Coordinating and scheduling the field inspector's activities in each district office is performed by an Associate Oil and Gas Engineer and supervised by a Senior Oil and Gas Engineer.

3. Do the inspectors perform all types of inspections or is there specialization of inspection responsibilities?

   Energy and Mineral Resources Engineers (EMRE) are responsible for witnessing MIT surveys, testing safety equipment, witnessing plugging and abandonment operations, etc.

   Oil and Gas Technicians (OGT) are responsible for the inspection of surface facilities, surface condition of wells, lease conditions, and check injection and tubing pressures. They do not witness mechanical integrity tests.

4. Do supervisors periodically accompany inspectors on field assignments?

   a) To observe and critique their work (please explain how often and the process?

      Yes. An Associate Oil and Gas Engineer will accompany an EMRE or OGT at least once annually.

   b) To ensure that inspections, tests required of operators and general observations of lease and well conditions meet a common standard of quality and fairness to operators?

      Yes.

   c) For other purposes (please explain how often and for what purpose(s)?

      Yes, a supervisor or Associate Oil and Gas Engineer may accompany an EMRE or OGT during enforcement cases.

5. Does the agency have a written inspection strategy, guidance manual or policy document which is available to inspectors? How are inspection priorities determined?

   Yes. The MOI is available to all Division employees. Inspections are performed regularly on all wells, but with no particular priority to operator or well unless there has been a deficiency or violation. In such cases, inspections are made more frequently until the problem is rectified and for a period thereafter to ensure continued compliance. The Division tries to achieve 100

percent inspection of all injection wells annually either through scheduled environmental lease/well inspections or during an MIT.

6. What professional qualifications and /or experience is required to be and inspector?

   Preferably, EMREs must have a minimum of a Bachelor's degree in geology or petroleum engineering; however, exceptions are made, based on experience. OGTs must have oil and gas field experience, but a Bachelor's degree is not required.

7. What training do inspectors receive? Initially upon employment? To keep trained on new regulations, industry techniques, etc.? Do inspectors receive training in safety procedures and is special safety equipment readily available?

   As mentioned above, EMREs have a minimum of a Bachelor's degree in geology or petroleum engineering and OGTs have oil and gas field experience. Each EMRE is teamed with another experienced EMRE and with an Associate Oil and Gas Engineer to receive additional training.

   Training in safety procedures is of high importance. Field engineers are trained in H2S safety, safety procedures around steam operations, rig pressure systems, safe fluid-sampling procedures, rig safety, and drivers training every four years. In addition, every EMRE is required to attend blowout equipment training.

   Protective clothing is required in the field (i.e., hard hat, steel-toed boots, and thick-soled shoes, etc.). Also, proficiency in use of medical kits, flares, gas mask for H2S, etc., is also taught.

   All Division employees are notified of statutory, regulatory, and policy changes through electronic mail and staff meetings.

   Other training consists of in-house training (videotapes), or what is provided by service companies, such as cementing companies, mud companies, well surveying companies, well equipment companies, etc.

   The Division budgets each year for college courses, conferences, seminars, and other training that is provided periodically.

8. What role do inspectors play in developing enforcement cases and to what extent are they involved in the hearing or judicial process?

EMREs carry out the documentation and follow-up inspections, including sampling and photographing violations. They are responsible for gathering all relevant information and presenting it to the District Deputy, who then takes appropriate action. In many cases, the field inspector who witnessed the field deficiency/violation would testify at a hearing as an eyewitness.

9. Is the operator compliance history and selection of wells coordinated for inspection at the field or central office level?

   Yes. Well files are maintained in each district office. All MIT and inspection activity is coordinated at the district office. Operators who have a history of certain violations may be monitored and inspected on a more frequent basis than other operators. Headquarters is informed verbally of such activity.

B. OBJECTIVE: Understand the routine/periodic inspection program in the state.

1. How often is each UIC permitted well inspected? Is there a different inspection periodicity for Class II ER than for SWDs?

   The Division attempts to inspect each UIC well annually while performing environmental lease/well inspections or through scheduled well inspections. In addition, MITs for disposal wells are performed at least once each year and waterflood wells are tested at least every two years. The Division attempts to witness most of these MITs, particularly water disposal wells, and during this time the well site is inspected also.

2. Who determines the inspection frequency for each UIC facility? Are UIC inspections done separately or are they generally coordinated with inspections of other permitted facilities on the lease?

   See response to question 1.

3. How is communication between field inspectors and the central office staff in charge of UIC permit review handled? Are inspections ever required after an Operator files an application but before technical review is completed?

   Field inspection is managed at the district office. The district communicates with the UIC program manager or Chief Deputy if needed. In addition, districts submit UIC information for US EPA reports quarterly to the UIC program manager and send a representative to the Injection Surveillance Committee meeting that is held periodically.

   Occasionally, but usually the Division does not begin inspecting a well until a permit has been issued.

4. How many UIC related inspections are conducted in an average month, which are not related to scheduled MITs? Discuss seasonal variations.

Approximately 600 per month.

5. What does the inspector look for during a routine inspection? Is there a checklist? (Please supply a copy of forms and checklists used).

Tubing and casing pressure, presence of a gauge, leaks (wells, pipelines, and tanks), fluid in cellars, check flow rate, general condition of equipment, general condition and cleanliness of well site, and proper well identification (Attachment 13).

6. What is the average length of time needed for a routine inspection? Include the amount of time needed for preparation, travel time, and time spent on location. Is the preparation performed by the inspection and/ or others? What review occurs during preparation?

Preparation time per well is about 15 minutes. Average travel time to the well ranges from 15 to 60 minutes. For some wells, travel time may exceed 1 hour. Location time will range from 10 to 20 minutes per well. Time at the well site may take longer if the engineer acquires a GPS location for the well.

7. Is the operator given advance notice of inspections? How much? Does the state inspectors have statutory right on ingress and egress from leases and UIC well locations to make unannounced inspections. What restrictions apply?

Not usually. In cases where pressure gauges are not permanently installed, the operator is notified to have a representative present to put gauges on for the inspection. Also, in cases where fluid samples are taken from an injection line or tank, the operator is notified. Short notice is emphasized in these cases to facilitate observing violations, if present. It is a misdemeanor, Section 3236 PRC, to refuse the Division access to inspect a well or lease.

8. Does the Operator receive a copy of the completed inspection report?

No, however a letter of noncompliance is sent to the operator when violations or deficiencies are noted. The letter is sent noting all deficiencies and requesting correction before reinspection by the Division. A letter of compliance is sent after reinspection if everything is repaired adequately.

9. Are df taken during an inspection? How does the inspector log photographs? Are their written procedures designed to preserve the legal integrity of photographs for potential enforcement actions or hearings?

Yes. Each injection well has a photo taken and kept on file as identification. Photos are attached to injection reports and filed in the well file. All photos are identified with a description (i.e., well number, lease operator, well location, date, time, field inspector). Negatives are filed in a photo file with subject and date. If a digital photo is taken, the photo will be stored in the electronic database. The Division uses videotape to record well operations and violations also. The tapes are labeled appropriately and stored.

Photographs are taken whenever an enforcement action is to be taken on the well or whenever a well has a serious deficiency (i.e., leak, spill, required equipment missing, high pressure, etc.).

10. Are samples of the injectate collected routinely at some/all inspections? How are samples documented, preserved and transported? Are analyses performed by State or private laboratories?

Random samples are taken at some sites for water analysis. Sampling is also performed whenever it is necessary to check compliance. Sampling procedures have been established and are described in the Division's EPA-approved Quality Assurance Plan.

<u>***Documentation***</u> ***– When samples are collected, a sampling form is filled out that describes the sampling technique used, where the sample was collected, and information related to sample preservation and chain-of-custody.***

<u>***Preservation***</u> ***– All samples are preserved according to lab recommendations; usually refrigeration at a particular temperature and/or a preservative is used.***

<u>***Transportation***</u> ***– if the lab collects the sample, the sample is taken to the lab for analysis. If the Division collects the sample, the field engineer takes the sample to the lab scheduled to do the analysis. In most cases, sampling and analysis is prearranged with the lab before the sample is collected.***

11. Do inspectors carry their own gauges and flow meters? How and how often are the gauges calibrated and how is this documented?

Division engineers carry no gauges and are not permitted to install gauges or operate oilfield equipment of any kind.

Operators are required to calibrate permanently affixed gauges every six months and portable gauges every two months (Section 1724.10(e), CCR).

12. What training does the inspectors received on the states QA/QC plan?

The Division's QA/QC plan is made available to each engineer. In addition, it is contained in the Division's MOI. QA/QC training is held in-house.

C. OBJECTIVE: Understand the emergency and citizen complaint procedures.

1. How is the state notified of emergency situations regarding oil and gas lease operations? What percentages of these incidents are associated with UIC permitted wells?

When a spill or emergency occurs, the operator is required to report the spill or emergency to the Division promptly and to the State's Office of Emergency Services (OES) and all other agencies indicated in their contingency plans. (OES is the overall State response agency to major disasters in support of local government. The office is responsible for assuring the State's readiness to respond to and recover from natural, manmade, and war-caused emergencies, and for assisting local governments in their emergency preparedness, response and recovery efforts. OES notifies all State agencies with jurisdiction over an incident. If conditions change at a spill site, the responsible party notifies OES of any significant changes. In addition, the Division will notify other agencies as necessary of any potential impacts to their jurisdiction.)

Emergencies for Class II wells are essentially nonexistent.

2. Who communicates with the inspectors and prescribes the response? Who performs the on-scene response and coordination?

Although most emergency and citizen complaints are handled at the district level, the gravity of the situation may require the State Oil and Gas Supervisor to be involved in the response. Usually, the districts handle most situations; however, Headquarters is kept informed.

If a Division engineer responds to a call, the engineer will remain on site until the cleanup or repair efforts are underway and well organized. Typically, the first responder on scene is responsible to coordinate activities as the on scene coordinator until replaced.

3. How is emergency response action documented? Is there written guidance that the agency uses to insure adherence with procedures that will produce acceptable documentation for possible enforcement action?

When a call comes in, it is forwarded to an engineer who fills out an emergency form (Report of Occurrence). The form includes details of the emergency, location, type, volume (if a spill), whether the emergency situation is under control, name of person making the call, a contact person, etc.

Yes, the MOI.

4. What is the procedure for conducting follow-up to emergency response events?

The site is inspected to assure that cleanup, if necessary, is proceeding in a timely manner and that any danger has been abated. Inspections continue until the problem is resolved to the satisfaction of the Division. After the incident, a report is completed and filed.

5. If the emergency requires notification of other agencies that may have their own regulatory issues to resolve (e.g. brine flow from a well into an aquifer or lake which is a public water supply), who does the notification?

The responsible party will notify the OES as part of their initial notification. OES is the overall State response agency to major disasters in support of local government. The office is responsible for assuring the State's readiness to respond to and recover from natural, manmade, and war-caused emergencies, and for assisting local governments in their emergency preparedness, response and recovery efforts.

6. What type of emergency situation has been reported that have involved UIC permitted wells?

Emergencies for Class II wells are essentially nonexistent. Although infrequent brine spills have occurred from tank leaks. Since tank settings have approved containment barriers to confine a spill to the area around the tank, a brine spill would not cause a significant threat.

7. What type of significant citizen complaints has been received? Are complaints responded to in accordance with a priority system or are all complaints investigated?

Very few citizen complaints have been received. Those that have been received are usually claims about a freshwater well being contaminated. Although there is no documented evidence an injection well harmed a freshwater well, public

fears in one county were escalated to the point injection wells were essentially prohibited because of increased bonding requirements.

All reports are investigated. Priority is given to those cases that are an immediate threat to humans, wildlife, or drinking water. Cases that may be a potential threat in the immediate future would be next and, lastly, any complaint that poses no real threat to life or drinking water.

8. Is the complainant routinely contacted prior to field investigation of the alleged problem and subsequently notified of the results of the complaint investigation?

   Yes, the Division follows up a complaint with a call or a letter.

9. Is the operator notified of the complaint?

   Yes, immediately.

10. What is the typical response time to complaints?

    Response time depends upon the nature of the complaint and whether the field engineers are available (i.e., witnessing tests or other cases of higher priority). If the complaint is received during working hours, the inspection is done during the day. If the complaint is received after hours, the inspector on call will determine the severity of the complaint. If severe, he/she will inspect the site immediately; if not severe, the incident will be investigated the following workday.

11. Is the agency obligated to routinely notify Federal agencies or other state agencies when an emergency occurs? Upon such notification, are their occasions where the lead for resolution of the emergency is transferred to another agency even if the permitting authority is the transferring agency?

    See response to question 5.

12. What is the agency's policy or procedure for communicating with the news media on an emergency situation or complaint? Who is responsible?

    Inquiries from the news media (reporters, editors, etc.) are referred to the Department of Conservation's Public Affairs Office (PAO) immediately. This procedure applies to virtually all inquiries, even most of those that appear to be technical in nature. PAO staff will obtain the information requested and respond to the inquiry, or request Division staff to provide the information directly to the media contact.

D. OBJECTIVE: To understand the reporting and follow-up procedures used in the inspection program.

1. Are there a standard inspection forms for routine inspections? For complaints or emergency situations? For inspections connected to well tests?

   There is a standard form for each different type of inspection (i.e., MIT, environmental, sample collection, witness of plugging and abandonment operations, etc.). The Report of Occurrence form is used to record details of an emergency or citizen complaint.

2. Do the inspectors take field notes and if so, are there retained or destroyed? If notes are retained, where is the repository?

   Yes, inspectors take handwritten notes that usually become part of the well record.

3. If the routine UIC well inspections are a part of a comprehensive evaluation of the lease operations, are the injection well inspections cross-referenced to the permit file? Where is this done?

   Yes. The field data is entered in the database and checked to ensure the well is permitted properly, the UIC permit is active, injection pressure is below MASP, etc. The crosschecking is done in the district office.

4. Does the state have a statute or policy regarding the destruction of potentially historical files that would affect the retention of field notes? Does this mandate or policy pertain to hard copy records or records retained in electronic format or both? Who makes the judgment on record retention or the length of time records are to be kept?

   No, significant field notes are retained in the well file. Because MIT well logs are generated regularly, file space becomes an issue. To address this issue, the State Oil and Gas Supervisor established a policy that allowed districts to purge MIT well logs older than 3 years.

5. What is the lag time between the inspection and write-up of the report? Does the Central Office receive copies of the reports as hard copy or by electronic transfer?

   Less than 24. An inspection report is retained in the appropriate district well file and no copy is sent to Headquarters.

6. Where and how are inspections, and violations revealed through inspections tracked to ensure compliance deadlines are met? Is this tracking system computerized or primarily manual?

An electronic database is used to track MITs, inspections, deficiencies, violations, etc. In addition, the field engineer will check the field results against the well file and database to ensure compliance. Deficiencies and violations are logged in an electronic tickler file to ensure follow up.

7. Has the State Counsel or agency Legal Department reviewed all inspection procedures to assure the results may be used in formal enforcement actions? Are form revisions routinely reviewed by the Legal Department? In the case of the UIC program, are such form drafts sent to EPA for comment?

Yes, the Attorney's General office acts as legal counsel for the Division. An attorney has been working closely with the Division for many years and is intimately familiar with the oil, gas, and UIC programs. The attorney has attended Division management conferences and provides information and advice on proper procedures. Because form revisions were considered routine and nonsignificant, the attorney or EPA did not review them.

8. Who reviews inspectors' reports? What is the lag time between submission of the report and review? Where is the review generally done?

A district's Associate Oil and Gas Engineer in charge of UIC reviews the field reports. The Associate Oil and Gas Engineer in charge of field inspection reviews the environmental field reports (smaller districts, one engineer performs both functions). Review of the inspection report is completed within one week, depending on work priority.

9. What is the inspector's access to UIC information in the field such as permit contents, letters to operators, notices of violation, etc.?

Field inspectors have access to all information in Division files, including confidential information. Typically, the field engineer will review pertinent information before leaving for the field.

10. Where are chain of custody, photograph negatives and analysis forms filed?

Forms and photographs are filed in the injection project folders and well files.

E. OBJECTIVE: To understand the Data Management Systems Accessible to Inspectors for Conducting Field Inspections and Addressing Emergency Situations.

1. Describe the data management system (s) which are available to field inspectors in conducting routine lease and well inspections as well as providing background support for responding to complaints and emergency situations. The description should delineate how the data management system(s) available to inspector's interfaces with the systems used the other oil and gas regulatory activities.

The Division's main database file contains over 150,000 well identifications, keyed on API number (work is proceeding to enter all wells in the database). A secondary database includes field inspection tables linked by API number or by a district-generated lease number. (Lease numbers became necessary to link multiple wells together along with tank farms and sumps.) Inspectors are able to download (at a docking station) the latest copies of the databases they use before commencing their inspections. They then have available to them the tests and results of those tests from past inspections. They also have the electronic versions of reports available to them to document any emergency situation encountered. They can also generate a Word document for any event not covered by a typical form. We do not have the hard copy information in the well files available to them for review in the field. Permit requirements, casing records, and other essential information still needs to be communicated by the dispatcher who sends the inspector to a site or by a company representative at the site.

At the end of the week, field inspectors have been able to update the office's network files from their laptop databases. Because of the size and weight of the laptops, most inspectors do not use them as primary recording instruments in the field. For this reason, we have been developing PDA data tables that would be easier and more convenient to use in the field.

2. When were the data management systems currently in use first put into operation?

The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet its needs.

In addition, production and injection from 1977 is stored electronically.

3. Are these systems sufficiently effective and efficient to allow inspectors to effect retrieval of data on wells, tests, past emergency situations thus minimizing unnecessary duplication of previous findings? What limitations exist in addressing basic regulatory and response needs of the inspector?

Yes, it has improved efficiency of the Division's oversight functions and access to information. The only limitation is getting the information stored electronically.

4. Are relevant data bases and systems of other agencies having authority for water resource allocation, water protection regulation, emergency response and water resource contamination accessible to inspectors and other field office personnel (if any)?

WellStat is available through the Division's web page. Other information is made available upon request.

5. What are the restrictions or limitations imposed on inspectors in the sharing of data with field personnel of other water resource agencies who may have cooperative functions on an investigation or may have a need to notify entities permitted by them of the findings?

The only restriction is confidential information. The RWQCB/Division MOA allows the agency to view confidential information related to a project; however, the agency must view the information in the district office.

F. Changes and Modifications to Program since 1990

Excluding the changes in **data management** described under Section E above, what statutory, regulatory, policy or budgetary changes have occurred during the past ten years that directly affect the UIC field inspection program? Please list or explain.

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years.

PART IV: MECHANICAL INTEGRITY TESTING

A. OBJECTIVE: Understand the Types of Mechanical Integrity Tests Allowed for different UIC well completion programs.

1. What types of MITs are acceptable to the state for satisfying the leak test (Part 1 of MI)? Are some tests acceptable only for a specific set of well completion conditions? Please list the tests and their limitation as to applicability.

A standard annular pressure test (SAPT) is required for all water-disposal and waterflood wells before commencing injection and at least once every five years thereafter. The advantages of conducting an annulus pressure test are: (1) some internal mechanical failures may be detected and (2) the well does not have to be taken out of service for monitoring to be performed.

However, internal MI can only be demonstrated partially with an SAPT because the presence of a leak in the tubing, packer, or casing may go undetected if the fluid pressure on the outside of the annulus is in equilibrium with the pressure imposed on the annulus. In such instances, pressure or fluid flow in the annulus is a better indicator of mechanical integrity failure.

The SAPT is inadequate as a sole demonstration of mechanical integrity because of given limitations, such as fluctuating injection fluid temperature, ambient air temperature, geothermal gradients, and heat transferred between fluids, tubulars, cement, and formations. In addition, the SAPT does not demonstrate that the injection fluid is entering the intended zone. Therefore, the Division utilizes the SAPT as a secondary method to monitor mechanical integrity.

2. What criteria (is, are) used for the pass/fail of a pressure test? Why were these criteria selected? Are the criteria more strict in sensitive ground water areas, wellhead protection areas, or areas of know corrosive ground waters?

   A. No perforations above the packer.
      1. *Hydraulic test - a minimum of 200 psi for at least 15 minutes, with a maximum pressure loss of 10 percent.*
      2. *Gas test - a minimum of 200 psi for at least 15 minutes, with a maximum pressure loss of 10 percent. Usually, nitrogen is used to pressurize the annular space.*

   B. Perforations and/or holes above packer.
      1. *Fluid level (sonic) test.*
         a) Must have cement behind casing (above perforations/holes).
         b) Perforations/holes must be below USDWs.
      2. *Pull tubing and packer, run a bridge plug, and pressure test.*

NOTE: Division approval must be obtained before the operator uses any other test method.

The ADA pressure test is a procedure that can be used for determining internal mechanical integrity in wells in which the fluid level is above the base of the USDW and there are known perforations and/or holes above the packer. It can also be used in tubingless wells, when such completions are allowed.

In the ADA pressure test, the fluid level in a well is measured to determine the height of the water column above the perforations. Then the pressure required to depress the column of water to the top of the perforations is calculated.

Nitrogen is then added to the annulus until the pressure no longer increases. If the test pressure stabilizes at or very close to the calculated pressure and remains constant for 30 minutes after closing the valve to the nitrogen source, no leaks in the casing above the perforations are indicated and mechanical integrity is demonstrated.

A. ***Testing Requirements***

1. ***The well should have at least 100 linear feet of cement behind the casing, immediately above the uppermost perforations/holes.***
2. ***The specific gravity or total dissolved solids (TDS) content of the water in the annulus must be known.***
3. ***There can be pressure on the tubing, but injection must be shut-in and the pressure stabilized. The well is shut-in long enough for temperatures to stabilize before the test.***
4. ***With the tubing and packer set at their normal injection depth:***
   a) ***A radioactive (RA) tracer survey must be run through tubing to demonstrate there is no leakage in the tubing or packer below the uppermost perforations/holes, or***
   b) ***The ADA pressure test may be used inside the tubing to demonstrate mechanical integrity of the tubing and packer if the distance between the injection perforations and the bottom of tubing is at least 50 feet, the water level in tubing is at least 200 feet above perforations, the fluid level is measured, and the specific gravity or TDS of fluid and the depth of perforations are known.***

B. ***Testing Requirements***

1. ***Calculate the pressure required to depress the column of water to the top of the perforations/holes:***

   Sp. gr. x 0.433 (if fresh water) = gradient (psi/ft. of head)

   Gradient x water column = psig

2. ***Pressurize the annulus (or tubing, if testing the tubing and packer) using compressed nitrogen cylinders. The number of cylinders required will depend on the volume of space above the perforations. (Be sure the hoses and the gauges are rated to handle the high pressure of the cylinders.)***

3. ***When pressure at the wellhead no longer increases, verify that gas is still flowing from the cylinder into the well, shut off the valve to the cylinders.***

4. ***Record the times and corresponding pressures. Monitor the pressure for 30 minutes. Record the pressure after 5, 10, 20, and 30 minutes. Fluid levels must be run during the test.***

3. Is the volume of fluid loss a factor in the determination of a failure?

   Yes, see answer above.

4. Is annulus pressure monitoring APM used to determine MI? How is an MI failure determined utilizing APM?

   Yes, only Part 1, see response to question 2.

5. How often is APM recorded? What is reviewed and who reviews it? Are there stricter standards imposed on wells located in special geological areas (faults, salt deposits, e.g.) or in ground water situations described under Section A-2. Above?

   It is recorded whenever this type of test is used, see response to question 2.

6. Are wells using APM required to have an initial pressure test?

   Yes, see response to question 1.

7. If other monitoring records are reviewed to establish MI, how are failures determined? If the determination of failure is different for each type of monitoring record, explain the process for each.

   Generally, no other monitoring records are used to determine mechanical integrity; however, the relationship between pressure and rate may be used as a trigger to run radioactive tracer surveys.

8. What type of technical judgment or MIT is used to satisfy Part 2 MI Fluid migration test)? If cement records are reviewed, what criteria are used to determine pass/fail?

   The Division relies on a combination of RA, temperature and spinner surveys to demonstrate external mechanical integrity. At least two of these three surveys must be employed for a complete MIT. The frequency of testing varies, depending upon the well type. After the initial MIT is conducted, water disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years.

   Cement records are never used to determine MIT.

9. Identify any logs used for the determination of MI and the limitations imposed on their use. Are logs more frequently used in areas where potential adverse geological situations are historical to past oil operations or where groundwater may be from vulnerable or artesian sources? Who interprets the logs or makes the decision to have the Operator runs special log suites? How are failures of MI determined?

See response to question 8. If a RA/temperature survey is witnessed, then the field engineer interprets the logs for pass/fail.

All injection surveys and logs submitted to the Division are reviewed and interpreted by the Associate Oil and Gas Engineer in charge of UIC.

The RA survey detects fluid movement. Any movement of fluid behind casing that migrates above the top of the injection zone behind casing is a failure. Also, any indication of fluid movement into the annulus through holes in the tubing or through a defective packer would constitute a failure.

The static temperature survey detects anomalous formation temperatures that usually indicate casing holes and/or cement failure. Any temperature anomaly is considered a failure unless proven otherwise by other tests.

A spinner survey detects changes in fluid volumes/rates. A decrease in rate (within the same size casing or tubing) usually indicates a hole in the injection string. RA surveys and temperature logs are used to verify the existence of fluid loss at points where there are rate changes.

10. What are the most common remedial actions required to correct MIT failures? Who performs the remedial action and /or plugging of the well if the Operator of the well proves to be insolvent?

The most common failure is a packer leak. The operator can remedy the failure by replacing and/or resetting the packer. The next most common failure is a casing hole.

The Division has a plugging and abandonment fund that is used to plug and abandon hazardous wells of defunct operators.

B. OBJECTIVE: Understand the Implementation of the MIT Program

1. What is the process for notifying an Operator that demonstration of MI is due? How much prior notice is given? Are tests scheduled at the Operators or states convenience?

The schedule for a Class II injection well MIT is determined by the date of the last MIT and the type of injection well (i.e., WD, WF, or SF). For new wells, an MIT is required within 90 days of commencing injection operations. The operator is responsible for scheduling the MIT and giving the Division sufficient notice to witness the test.

2. If tests are scheduled at the state's convenience, is consideration given to having an Operator run MITs on large numbers of wells in the same area in accordance with an efficient schedule?

   Normally, operators try to schedule wells in the same area to keep costs down.

3. What is the priority schedule of wells to be tested? If the general cycle for testing is five years are there wells tested on a more frequent schedule and, if so, what are the criteria?

   After the initial MIT is conducted, water-disposal wells are tested annually, waterflood wells are tested biennially, and steamflood wells are tested every five years.

4. How are the pressure test and fluid migration test (Part I and II of MIT) coordinated?

   These are two different tests and they are normally are not coordinated.

5. How are the MIT results filed and managed? In those cases where the well passed the test? In those cases where test failure occurred and follow-up for compliance purposes is necessary?

   Districts log MIT results in the electronic database and in the injection project file. A technical reports (T-Reports) is completed and filed in the well file for each MIT witnessed by the Division. The original copy is sent to the operator indicating the results of the test and whether any further action is necessary. The operator is required to submit all MIT logs (i.e., RA, temperature, spinner logs) to the Division. All logs are reviewed by the Division to evaluate for mechanical integrity and results are entered in the database.

6. What are the personnel (inspector) resources required to implement the MIT program? Does this vary significantly from one year to the next? During periods within the industry where economic exhilaration or depression occurs?

   The personnel resources required to implement the MIT program do not vary from year-to-year significantly.

Personnel time: *In office maintaining compliance schedules.*
In office maintaining files.
In office preparing for MIT witnessing.
In office reviewing MIT surveys.
In field witnessing tests.

Transportation: *Cost of transportation, including vehicles and maintenance.*

C. OBJECTIVE: Understand the procedures of witnessing a Mechanical Integrity (MI) test.

1. Who witnesses MI demonstrations and what percentages of MI tests are witnessed by State inspectors? Does witnessing vary from one producing region of the state to another?

   Normally, the operator notifies the Division of the time and date that an MIT will be conducted. Division engineers (EMRE) witness the entire MIT. The majority of MITs are witnessed. Those well tests not witnessed by the Division are reviewed when the operator submits a copy of the MIT log.

2. What do inspectors look for during an MI demonstration? Are routine inspections of the other lease facilities conducted at the same time as a visit for MIT?

   A static temperature log is run to look for anomalies in wellbore temperature that would show water going out through a hole in casing or tubing, or a packer leak.

   The RA survey shows leaks in packer, casing, tubing, and will show any fluid migration behind casing.

   The main intent is to determine if fluid is confined to the zone of injection, and to detect fluid movement at other points within the casing and tubing.

   Normally, environmental lease inspections are a scheduled event. An engineer witnessing an MIT may conduct inspections of other wells while in the area of the MIT. However, their time may be limited if they have other MITs to witness.

3. How much time is spent witnessing an average MI test? This estimate should also include travel time. Are there occasions where the Operator is not set up to do the test at the appointed time?

   From 3 to 8 hours, depending on how smoothly the equipment runs.

4. How is the witnessing of MIT documented? What documentation is required of the Operator in those cases where the test was not witnessed?

T-Reports are completed for each MIT witnessed. The reports are filed in the well file, the database is updated, and a copy of the report is sent to the operator. The operator is required to submit a copy of the MIT log to the Division. The Associate Oil and Gas Engineer in charge of UIC evaluates the log.

5. What action does the inspector take in those cases where it is discovered that the Operator conducted a MIT prior to the scheduled time and subsequently made repairs? Does the State required documentation of the work even though the action was taken voluntarily by the Operator?

The operator is required (project approval letters) to notify the Division anytime a loss of mechanical integrity has taken place. The operator is required to conduct an SAPT anytime the packer is pulled and submit a history (documentation) of the repair work to the Division, even if no notice is required.

D. Follow -Up on failed MI tests

1. In the event of MIT failure, how is the operator notified to shut the well in? If all wells failing MI are not shut in, please elaborate.

When an engineer witnesses an MIT and the test fails, the field engineer informs the operator that the well must be shut-in and the well repaired. A follow-up letter is sent and a follow-up visit is made to ensure compliance.

When the log of an unwitnessed survey is reviewed and a leak is detected, the operator is notified by phone to shut in the well. A field inspection is made to confirm compliance. If a well is not shut in when directed by the Division, a formal order may be issued.

The following are guidelines to follow when MIT's are delinquent or fail:

<u>Delinquent Mechanical Integrity Test (MIT)</u>

a) Survey is determined delinquent.
b) Operator is notified to run an MIT within 60 days.
c) If the operator does not run the MIT within 60 days as directed, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to:
(1) Shut-in the well within 24 hours.
(2) Disconnect the injection line at the wellhead within 10 days.
(3) Notify the appropriate district office when the injection line has been disconnected.

The District Deputy rescinds the permit if the MIT is not run within 90 days.

INTERNAL MECHANICAL INTEGRITY FAILURE

1) **Tubing Or Packer Failure**
   a) ***Unless it is a situation where immediate damage to a USDW cannot occur, the District Deputy issues a written order to shut-in the well within 24 hours, and to repair the well within 60 days. When appropriate, the operator must file a notice and receive a permit before work is commenced.***
   b) ***If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to: (1) shut-in the well within 24 hours (if the well is still active); (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.***
   c) ***An MIT is required following repair if the well is returned to injection.***
   d) ***The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.***

2) **Casing Failure Located Below The Packer**
   a) ***If fluid is exiting a hole or cemented-off perforations (e.g., WSO) located below the packer, but within the permitted zone, no action is necessary. However, a recalculation of the maximum allowable surface pressure may be necessary.***
   b) ***If fluid is exiting a hole or cemented-off perforations (e.g., WSO) located below the packer and is entering a zone that has received an aquifer exemption, but has not been permitted for injection by the Division:***
      1. ***The operator must either repair the mechanical problem or amend the project to include the nonpermitted zone into the injection project by submitting the required project data within 60 days. If the operator chooses to amend the project to include the new zone, the Division will issue a revised project approval letter. No further injection is permitted until the project receives approval.***
      2. ***If the operator fails to repair the well or amend the project within 60 days, the District Deputy may rescind the permit.***
      3. ***An MIT is required following repair if the well is returned to injection. If the operator fails to run the MIT.***
      4. ***The District Deputy must rescind the permit if the operator fails to repair the well or amend the project within 120 days.***
      5. ***If fluid is exiting a hole or cemented-off perforations (e.g. WSO) located below the packer and is entering a USDW, the operator must shut-in the well immediately and:***
         a. ***The operator is ordered to repair the well within 60 days.***

b. If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to disconnect the injection line at the wellhead within 10 days and notify the appropriate district office when the injection line has been disconnected.

6. An MIT is required following repair if the well is returned to injection.

7. The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.

8. An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with technical evidence and reported to the UIC Project Manager.

3) If a casing hole located above the packer is in the permitted interval:
- *a) The packer may be raised above the hole, making the hole the top perforation, or*
- *b) Without raising the packer, the operator must demonstrate mechanical integrity or develop a monitoring program.*

2) If a casing hole is located above the packer and is above the permitted interval, the operator must demonstrate MI or develop a monitoring program.

NOTE: A monitoring program should be designed as an early warning system to prevent USDW contamination. Periodic fluid level testing behind casing is one method of preventing USDW contamination.

3) If a casing hole is located above the packer and in a USDW:
- *a) The operator is ordered to repair the well within 60 days.*
- *b) If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit.*
- *c) An MIT is required following any repair if the well is returned to injection.*
- *d) The District Deputy must rescind the permit if the operator fails to repair the well within 120 days.*

EXTERNAL MECHANICAL INTEGRITY FAILURE

Migration Outside Casing Confined To Permitted Zone

If fluid exiting the approved perforations is not confined to the perforated interval, but is confined to the permitted zone, no action may be required other than monitoring as needed. An explanation and justification of the approved condition is included in the well file, even if no action is required of the operator.

Migration Outside Casing Not Threatening A USDW

If fluid exiting the approved perforations is not confined to the permitted zone and does not pose a threat to a USDW:

1. ***The operator must repair the mechanical problem or amend the project to include the nonpermitted zone in the injection project by submitting the required project data within 60 days. No further injection is permitted until the project receives approval.***
2. ***If the operator fails to repair the well or amend the project within 60 days, the District Deputy must rescind the permit.***
3. ***An MIT is required following repair if the well is returned to injection.***

Migration Outside Casing Threatening A USDW

1. ***If fluid exiting the approved perforations is not confined to the permitted zone and is determined to pose a threat to a USDW, the operator is ordered to shut-in the well within 24 hours.***
2. ***Operator is ordered to repair the well within 60 days.***
3. ***If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well within 24 hours (if the well is still active); (2) disconnect the in the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.***
4. ***An MIT is required following repair if the well is returned to injection.***

Migration Outside Casing Invading A USDW Or Flowing To Surface.

1. ***The operator is ordered to shut-in the well immediately and make repairs within 60 days.***
2. ***If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well immediately (if the well is still active); (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.***
3. ***An MIT is required following repair if the well is returned to injection.***
4. ***An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with strong technical evidence and reported to the UIC Project Manager.***

2. Is the Operator required to institute corrective measures for each failed MI? If an alternative to effecting corrective measures is the plugging and abandonment of the well, does the State ever require the Operator to repair the well prior to plugging?

   Yes. If a well is plugged and abandoned, the permit will stipulate placement of plugs, squeezing of cement, etc. necessary to protect the environment.

3. How long is the Operator given to complete repairs?

   See response to question 2.

4. Are repairs witnessed (what percentage)?

   Depends on the type of repair. For example, the Division may witness the squeezing or placement of cement, but not witness the replacement or resetting of a packer. However, the Division will witness the follow up MIT to ensure compliance.

5. If workover of the well is required as a part of repair, does the state require copies of reports documenting the work? Does this include such activities as well fracturing or removal of scale to enhance intake capacity?

   Yes, if the repair permanently altered the casing.

6. What are the current MI failure rates for enhanced recovery and disposal wells? How has the failure rate changed through successive five-year cycles of testing?

   The majority of wells pass MIT. The only correlation in failure rates is the age of the well and tubing/packer.

E. OBJECTIVE: Understand the data management of the MIT program

Describe the data management system(s) used in the various components of the MIT program as set forth in Section A-D. The description should delineate how the system manages the program from test scheduling to follow up on failure.

1. When was the MIT data management system currently used first put into use?

   The Division began using computers in 1986 to store and manage well information. Each district took the initiative to develop a database to meet their needs.

   In addition, production and injection from 1977 is stored electronically.

2. Is RBDMS used by the State as a tool to determine when MITs should be conducted in certain areas of the State and if such tests should be conducted more frequently than five years?

   No, the Division developed its system in-house.

3. Is the MIT database used by the agency conceived as an intramural system or is it linked with other state water protection databases?

   It is a stand-alone system; however, some UIC data can be accessed from the Division's web page.

F. Changes and modifications to program since 1990

Exclusive of the changes in data management described under Section E, what statutory, regulatory or policy changes have occurred during the past ten years in the MI Testing program. Please list changes or explain.

In 1996, Section 1724.10(j)(1) of the CCR was added to include mechanical integrity testing of the casing-tubing annulus every five years.

PART V: COMPLIANCE/ ENFORCEMENT

A. OBJECTIVE: Understand enforcement procedures in the state.

1. What types of enforcement tools and legal actions (formal and informal) are available to the State? Indicate which are available through direct agency action and which are dependent upon other enforcement authorities (Attorneys General, County Attorney, or Federal)

   The Division has the authority to issue orders in several specific situations. Orders may be issued to:

   - ***Plug and abandon wells***
   - ***Repair wells***
   - ***Screen or eliminate hazardous sumps, or shut down an oil and gas production operation sustaining a hazardous sump***
   - ***Discontinue unreasonable wastage of gas***
   - ***Adopt a well-spacing plan***
   - ***Adopt a repressuring plan to ameliorate subsidence***
   - ***Unitize or pool separate producing properties***
   - ***Undertake such action as is necessary to protect life, health, property, or natural resources.***

   Generally, a written order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. If an emergency exists, District Deputies can obtain authorization from Headquarters to repair or plug wells or eliminate hazardous conditions without issuing a formal order or seeking bids. If a well is bonded, the surety company will also be sent a copy of the order.

   Orders can be appealed to the Director of the Department of Conservation within 10 days of issue.

   If the operator refuses to do the work outlined in the order, or work is not commenced in a timely manner, the Division can proceed to do the work and place a lien (Section 3423(a), PRC) on the operator's assets or property.

The Division has the authority to impose a civil penalty of not more than $5,000 for any violation of the PRC (Section 3236.5, PRC), or any implementing regulation. The penalty can be appealed to the Division.

The Division may deny permits for new wells if the operator fails to pay a civil penalty and other charges that are required by the Division, such as the oil and gas production assessment. The Division may also shut in production on a well where an unresolved violation is occurring and the civil penalty has been paid.

2. What sort of formal enforcement actions have been taken relative to UIC violations? Roughly, what percentage of enforcement actions taken by the agency does this represent?

Orders have been issued to:
- ξ ***Rescind injection permits***
- ξ ***Shut-in wells***
- ξ ***Repair wells***

Civil penalties have been issued for:
- ξ ***Not filing required records.***
- ξ ***Not filing notice for work done.***
- ξ ***Injection of fluid without permit.***
- ξ ***Change of fluid stream without notice.***

Very few UIC enforcement actions have been necessary. Less than 5 percent of Division enforcement actions have focused on UIC operations.

3. What is the nature of the appeals process available to the Operator? Does the UIC staff get involved in the appeals?

The appeal must be a written statement filed by the operator, surety, or landowner with the Supervisor, District Deputy, or Director. The appeal must state that the order is unacceptable and that appeal from the order is taken to the Director under provisions of Section 3350, PRC. The appeal must be filed within 10 days of the service of the order (i.e., within 10 days following the date noted on the returned receipt acknowledging delivery of the order).

Within 20 days from the taking of the appeal, the Director must give an appellant 10 days notice in writing of the time and place of a hearing, except for good cause, and requires the Director to make a written decision with respect to the order appealed from within 20 days after hearing the evidence.

Following receipt of an appeal, the District Deputy will prepare a "fact sheet" outlining the events leading to the order, to be forwarded to the Supervisor with the appeal. This material will be submitted to the Director, who will then call for a hearing.

UIC staff would be involved during the case preparation and, most likely, to provide testimony in a hearing, if held.

4. Who evaluates field reports for violations and possible enforcement actions?

   The field engineers are well trained and knowledgeable in Division regulatory and legal requirements. Therefore, they would be the first to evaluate the field situation and make recommendations to the Associate Oil and Gas Engineer in charge of UIC. The Associate would evaluate the report and report to the Deputy.

5. How and who develops formal enforcement cases?

   Initially, the District UIC staff would work up the details to be included in any formal order. The details are a complete record of all events, inspections, observations, correspondence, etc. involving the case. The District Deputy prepares a fact sheet containing all the details about the violation and then issues the order. A copy of the fact sheet and order is sent to the State Oil and Gas Supervisor for his review.

   Civil penalties are considered, usually, after other attempts to obtain compliance have failed. Any and all attempts to contact an operator regarding operations that are out of compliance are documented, and may be presented as evidence during a hearing (if necessary). Any well locations or attendant facilities found not to be in compliance with regulations are brought to the attention of the operator on an informal basis (e.g., verbal discussions and deficiency letters). The operator is requested to submit a plan to achieve compliance within a reasonable time. If informal contact fails to bring results, then a Notice of Violation (NOV) outlining specific violations and corrective action to be taken is sent. If corrective action is not taken within 30 days, a civil penalty or other legal action is taken.

6. Who drafts the required documents and who reviews the proposed action?

   The District Deputy or his staff Senior Engineer. Mostly, the District staff prepare the documents.

7. When hearings are held on an appealed violation, what is the standing of environmental organizations or concerned citizens and their opportunity for input?

All hearings will be conducted in accordance with the Administrative Procedures Act. Headquarters will notify the operator, district office, Department of Fish and Game, and any other interested parties of the hearing outcome. Headquarters will then determine the appropriate action to take.

B. Nature and disposition of "Paper" violations versus technical and mechanical violation.

1. Is there a difference in procedures when penalties are imposed for "paper violations and for violations which may threaten USDWs? Are fines and penalties issued automatically for some violations? For all violations? For no violations?

   No. Although civil penalty amounts will vary depending upon the violation, penalty procedures are the same no matter the violation. There is no Division statute or policy that automatically imposes a penalty for a violation.

2. Does the agency issue Notices of Violation (NOV) and attached penalties? If so, who issues the NOVs and who tracks payment by the Operator?

   No violation notice or letter issued by the Division will have an attached civil penalty. However, the Division has imposed civil penalties without issuing a NOV or letter to operators habitually out of compliance (i.e., failure to file monthly injection reports) and has been subsequently warned. Civil penalties have been imposed without Division warning for well work performed without the required permit.

3. What are the follow up procedures to assure compliance and correction of the non-compliance event? Who does the follow-up and where is the report of the status sent?

   Operations found out of compliance are brought to the attention of the operator on an informal basis. A letter is sent identifying the problem and requesting that the problem be corrected within a reasonable amount of time.

   If the initial request fails to bring results, a second letter or notice is sent identifying the specific violations and that corrective action is required by a specific date, or a civil penalty may be issued. The second letter is sent via certified mail, return receipt requested. A reasonable amount of time is given to bring the operations into compliance. The second letter is identified as such, and as the final notice.

   If corrective action is not taken within the prescribed time, a civil penalty may be imposed. Civil penalties are issued in two steps: a Provisional Order Imposing Civil Penalty, and a Final Order Imposing Civil Penalty.

The district engineers perform the follow up and Headquarters is kept informed.

C. Time Allowance for Corrective Action

1. How much time is granted to an Operator to correct a "paper violation" or a violation that involved the issuance of a NOV?

   30 days.

2. How much time is granted to an Operator to correct a violation (condition) that if left uncorrected could threaten a USDW? Please provide a range of situations and associated time allowances.

   This could vary. If the threat is imminent, corrective action is immediate. However, if it is an implied threat, the operator has 30 days to correct the violation. Examples:

   Imminent threat to USDW – a hole developed in an injection well and fluid was exiting across a USDW zone. The well was shut in and well work to repair the hole was completed immediately.

   Threatens USDW – violations such as high injection pressures, i.e., pressures greater than MASP, but less than fracture pressure, or pressures needed to raise the injection fluid to the base of the USDW), would require urgent attention. The Division informs the operator of the violation verbally, a follow up field inspection may not occur for 30 days.

3. How much time is allowed the inspectors to perform follow-up inspections and report submission on C-1 and C-2?

   Whatever it takes to ensure compliance. How quickly an inspector follows up depends on the several factors, mostly severity of the violation and well location. Operators may have up to 30 days after service of an order to comply with the order. If an operator fails to commence or complete the necessary work and the violation threatens a USDW, the inspector will follow up as soon as possible following the compliance period stipulated in the NOV.

D. Flow from Non-Compliance to Enforcement Action

1. How and when are field violations escalated into formal enforcement actions?

   Generally, a written order is issued only after a reasonable attempt to obtain voluntary compliance with requirements has failed. Any well locations or attendant

facilities found not to be in compliance with regulations is brought to the attention of the operator on an informal basis (e.g., verbal discussions and deficiency letters). The operator is requested to submit a plan to achieve compliance within a reasonable time. If informal contact fails to bring results, then a NOV outlining specific violations and corrective action to be taken is sent. If corrective action is not taken within 30 days, a civil penalty or other legal action is pursued.

2. Are Operator bonds and license revocations (if applicable) reviewed as a part of initial enforcement action and under what conditions are bonds called in?

   Yes. Generally, bonds are forfeited when an operator fails to plug and abandon a well or wells, but can also be forfeited for other reasons, such as failure to clean up a spill or screen a sump associated with a well. In addition, the Division may deny permits for new wells if the operator fails to pay a civil penalty and other charges that are required by the Division, such as the oil and gas production assessment. The Division may also shut in production on a well where an unresolved violation is occurring.

3. Is there coordination with other State or local agencies (RCRA, NPDES, EPCRA, SDWA etc.?

   There may be coordination with EPA if the division is unable to achieve compliance or coordination of the operator. In addition, the Division MOA with the SWRCB outlines the procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. These procedures are intended to provide a coordinated approach that results in a single permit that satisfies the statutory obligations of both parties. The procedures ensure that construction or operation of oil, gas, and geothermal injection wells and surface disposal of wastewater from oil, gas, and geothermal production does not cause degradation of State waters.

4. What actions have been taken in response to enforcement actions? What penalties have been assessed and collected on UIC violations?

   Penalties have been issue and collected on just about every type of violation. Fines for failure to file records, filing fraudulent reports, failure to file for a permit, change in fluid stream without notifying the Division, plug and abandon wells without a permit, inject without approval, inject non-Class II fluids, etc.

5. How and who determines when the non-compliance event has been successfully resolved and the Operator can reactivate the well? Is this accomplished by formal order from the agency or by other communication?

The inspector will revisit a site to determine whether the violation was corrected. Once a violation is corrected, the Division will follow up with a letter.

6. Identify and list the more prevalent UIC related problems faced by the State in providing adequate enforcement?

   The Division has adequate field presence to insure compliance; however, addition staff could be place in the field to witness more MITS.

E. State/ Federal Enforcement Action Interface

1. Describe the existing cooperative relationship with the EPA Region on UIC violations. Are significant non-compliance events being reported to EPA?

   The Division has an excellent working relationship with the EPA and keeps them informed on UIC related issues. Only one or two significant non-compliance events have occurred in California since primacy was granted in 1983.

2. Has the agency ever requested EPA to take over enforcement on an UIC violation? Has EPA ever over filed on a case during enforcement proceedings by the state? If so, what was the result?

   No to all of the above.

F. Contamination/alleged contamination resulting from injection well practices or associated activities in the last ten years.

The purpose of these questions is to determine the extent of reports of alleged and proven USDW contamination resulting from "current" UIC practices or practices associated with UIC well completion and construction.

1. Estimate the number of alleged USDW contamination incidents reported to the State in the past ten years. Were any of these associated with such activities as hydraulic fracturing, zone acidizing or other well stimulation activity?

   None.

2. What actions are taken by the state when an alleged contamination report is received?

   N/A

3. How many of such contamination cases were found to be actual and were proved to be as a result of failure of an injection well or wells? How many were due to abandoned, unplugged injection wells?

   N/A

4. As related to question #3 and to the degree possible, briefly describe the well failure, the extent of contamination and any remedial and /or enforcement actions taken?

   N/A

G. Changes in Compliance or Enforcement Capability Since 1990

What statutory, regulatory, or policy changes have occurred during the past ten years in the agency's compliance/enforcement program? Have these changes been generated at the state level or by changes in the EPA Class II UIC regulations or State primacy agreement?

In 1996, the regulations, Section 1724.10(j)(1), were amended to include mechanical integrity testing of the casing-tubing annulus every five years. This change occurred in response to EPA's requirement that two conditions of an MIT must be met. The Division codified regulations to ensure there is no significant leak in the casing, tubing, or packer (this is referred to as <u>internal mechanical integrity</u>) of an injection well.

PART VI: ABANDONMENT/PLUGGING

A. OBJECTIVES: Understanding and documenting the technical aspects of Plugging and Abandonment (P&A)

1. For each major type of well construction, what techniques of plugging are approved? (Give detail on minimum plug size or length: use of mud between plugs and weight: use of bridge plugs; standard plugs at the pay or injection zone, base of freshwater or casing stubs etc;).

Approved plugging techniques are usually the same for injection and production wells, however, there are different requirements for cased vs. open hole. The majority of cement plugs in open hole or in cased hole are place through tubing into a mud-filled hole. The placement of a plug with a bailer is permitted only at a depth no greater than 3,000 feet. However, the bailer method is seldom used. See Sections 1723 – 1723.8, CCR, for specific plugging and abandonment requirements.

1723. Plugging and Abandonment--General Requirements

(a) Cement Plugs. In general, cement plugs will be placed across specified intervals to protect oil and gas zones, to prevent degradation of usable waters, to protect surface conditions, and for public health and safety purposes. At the discretion of the district deputy, cement may be mixed with or replaced by other substances with adequate physical properties.
(b) Hole Fluid. Mud fluid having the proper weight and consistency to prevent movement of other fluids into the well bore is placed across all intervals not plugged with cement, and poured into all open annuli from the surface.
(c) Plugging by Bailer. Placing of a cement plug by bailer is not permitted at a depth greater than 3,000 feet. Water is the only permissible hole fluid in which a cement plug shall be placed by bailer.
(d) Surface Pours. A surface cement-pour is permitted in an empty hole with a diameter of not less than 5 inches. Depth limitations are determined on an individual well basis by the district deputy.
(e) Blowout Prevention Equipment. Blowout prevention equipment may be required during plugging and abandonment operations. Any blowout prevention equipment and inspection requirements are prescribed on the permit to abandon.
(f) Junk in Hole. A diligent effort is made to recover junk when such junk may prevent proper abandonment either in open hole or inside casing. In the event that junk cannot be removed from the hole and fresh-saltwater contacts or oil or gas zones penetrated below cannot therefore be properly abandoned, cement is downsqueezed through or past the junk and a 100-foot cement plug is placed on

top of the junk. If it is not possible to downsqueeze through the junk, a 100-foot cement plug is placed on top of the junk.

1723.1. Plugging of Oil or Gas Zones

(a) Plugging in an Open Hole. A cement plug is placed to extend from the total depth of the well or from at least 100 feet below the bottom of each oil or gas zone, to at least 100 feet above the top of each oil or gas zone.
(b) Plugging in a Cased Hole. All perforations are plugged with cement, and the plug extends at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
(c) Special Requirements. Special requirements may be made for particular types of hydrocarbon zones, such as:
(1) Fractured shale or schist;
(2) Massive sand intervals, particularly those with good vertical permeability; or
(3) Any depleted productive interval more than 100 feet thick.
As a minimum for an open-hole abandonment, the special requirement consists of a cement plug extending from at least 100 feet below the top of the oil or gas zone to at least 100 feet above the top of the zone.
As a minimum for a cased-hole abandonment, the special requirement consists of a cement plug extending from at least 100 feet below the top of the zone to at least 100 feet above the top of the perforations, the top of the landed liner, the casing cementing point, the water shutoff holes, or the zone, whichever is highest.
(d) Bridge Plug. A bridge plug above the lowermost zone in a multiple-zone completion may be allowed in lieu of cement through that zone if the zone is isolated from the upper zones by cement behind the casing.

1723.2. Plugging for Freshwater Protection

(a) Plugging in Open Hole.
(1) A minimum 200-foot cement plug is placed across all fresh-saltwater interfaces.
(2) An interface plug may be placed wholly within thick shale if such shale separates the freshwater sands from the brackish or saltwater sands.
(b) Plugging in a Cased Hole.
(1) If there is cement behind the casing across the fresh-saltwater interface, a 100-foot cement plug is placed inside the casing across the interface.
(2) If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug is placed inside the casing across the fresh-saltwater interface.
(3) Notwithstanding other provisions of this section, the district deputy may require or allow a cavity shot immediately below the base of the freshwater sands.

In such cases, the hole is cleaned out to the estimated bottom of the cavity and a 100-foot cement plug is placed in the casing from the cleanout point.

(c) Special Plugging Requirements. Where geologic or groundwater conditions dictate, special plugging procedures are required to prevent contamination of usable waters by downward percolation of poor quality surface waters, to separate water zones of varying quality, and to isolate dry sands that are in hydraulic continuity with groundwater aquifers.

1723.3. Plugging at a Casing Shoe

If the hole is open below a shoe, a cement plug extends from at least 50 feet below to at least 50 feet above the shoe. If the hole cannot be cleaned out to 50 feet below the shoe, a 100-foot cement plug is placed as deep as possible.

1723.4. Plugging at the Casing Stub

When casing is recovered from inside another casing string (or strings), and the outer string (or strings) is cemented opposite the casing stub, a 100-foot cement plug is required on the casing stub. A plug on the casing stub will generally not be required when casing is recovered in open hole or from inside another casing string that is not cemented opposite the casing stub.

1723.5. Surface Plugging

The hole and all annuli is plugged at the surface with at least a 25-foot cement plug. The district deputy may require that inner strings of uncemented casing be removed to at least the base of the surface plug prior to placement of the plug.

All well casing is cut off at least 5 feet below the surface of the ground. In urban areas, as defined in Section 1760(e), a steel plate at least as thick as the outer well casing is welded around the circumference of the outer casing at the top of the casing, after division approval of the surface plug.

1723.6. Recovery of Casing

(a) Approval to recover all casing possible will be given in the abandonment of wells where subsurface plugging can be done to the satisfaction of the district deputy.

(b) The hole is full of fluid prior to the detonation of any explosives in the hole. Only a licensed handler with the required permits shall utilize such explosives.

1723.8. Special Requirements

The supervisor, in special cases, may set forth other plugging and abandonment requirements or may establish field rules for the plugging and abandonment of wells. Such cases include, but are not limited to:

(a) The plugging of a high-pressure saltwater zone.

(b) Perforating and squeeze-cementing previously uncemented casing within and above a hydrocarbon zone.

2. Does the state have any geological standards, tables or other technically based policy documents available to field staff which are used as a guide in plugging wells?

   American Petroleum Institute publications and the MOI.

3. Are there wells with no surface casing? How are they plugged?

   None.

4. If pipe is pulled (surface, intermediate or otherwise), what special plugging procedures are followed?

   A 100 foot plug is required above the casing stub; however a plug on the casing stub will generally not be required when casing is recovered in open hole or from inside another string that is not cemented opposite the casing stub.

5. Are plug locations verified? When and how? Are inspectors present to witness the plugging?

   The Division requires witnessing the tag of the:

   ξ ***Base of freshwater plug.***
   ξ ***Zone plug (open or case hole).***
   ξ ***Mudding placement between plugs.***
   ξ ***Cavity shot.***

   The Division may witness the tag or placement of the:

   ξ ***Shoe plug.***
   ξ ***Casing stub plug.***
   ξ ***Surface plug.***

   1723.7. Inspection of Plugging and Abandonment Operations

Plugging and abandonment operations that require witnessing by the division is witnessed and approved by a division employee. When discretion is indicated by these regulations, the district deputy determines which operations are to be witnessed.

(a) Blowout prevention equipment--may inspect and witness testing of equipment and installation.

(b) Oil and gas zone plug--may witness placing and shall witness location and hardness.

(c) Mudding of hole--may witness mudding operations and determine that specified physical characteristics of mud fluid are met.

(d) Freshwater protection:

(1) Plug in open hole--may witness placing and shall witness location and hardness. Plug in cased hole--shall witness placing or location and hardness.

(2) Cementing through perforations--shall witness cementing operation.

(3) Cavity shot--may witness shooting and shall witness placing or location and hardness of required plug.

(e) Casing shoe plug--shall witness placing or location and hardness.

(f) Casing stub plug--shall witness placing or location and hardness.

(g) Surface plug--may witness emplacement and shall witness or verify location.

(h) Environmental inspection (after completion of plugging operations)--shall determine that division environmental regulations (California Administrative Code, Title 14, Subchapter 2) have been adhered to.

6. What percentage of well plugs is witnessed? If all wells are not witnessed by inspectors, is there a priority system, which determines those plugs to be witnessed in all cases (producing wells, injectors, D&A)?

   About 80% of all plugs are witnessed. It is a priority to witness the base of fresh water plugs first, zone plugs second, shoe plugs and stub plugs third and non-critical plugs (such as across blank pipe opposite injection zones, damaged casing, etc.) last. All surface plugs are witnessed. The type of well is rather irrelevant to our priorities unless it's something like a mandatory squeeze of an injection well to seal off vertical migration.

7. Are plugs required to be tagged and if so, is the tagging witnessed? Is plug tagging required by regulation, elective on the part of the agency, or limited to certain geological or hydrogeological situations?

   Yes, Division regulations require witnessing and tagging of plugs. See response to question 5.

8. What control is exercised over unwitnessed plugs?

When a well is plugged and abandoned, the operator has 60 day to submit the complete record of operations to the Division (Section 1724 – 1724.1, CCR). These records are required to include all cement plugs, amount of cement, details of the cement job where tubing was hung, pump pressure, etc. An engineer reviews the submitted records and adds them to the well file. For unwitnessed plugs placed in a hole prior to the arrival of an inspector, the field inspector can check the tour reports at the well before plugging and abandonment is complete.

B. Understand the non-technical aspects of P&A and how this activity is integrated with the remainder of the program.

1. How are P&A reports coordinated with the permitting/area of review process?

   They are not coordinated with the area of review (AOR) process. An AOR is performed during the permit approval process for an injection project and/or injection well. The plugging and abandonment of a well subsequent to an AOR are engineered

2. Where are plugged and abandoned injection wells tracked? In the Central or district office? By whom?

   The tracking of plugged and abandoned wells is done by district office staff using the WellStat database.

3. What is the flow of activity starting with the Operators notice to the agency of an intention to plug a well through the submission of the final report?

   The operator submits a Notices of Intention to Abandon Well (permit application) to the appropriate Division district office. The notice is date stamped and the statutory 10-day (working days) clock starts in which the Division must respond to the operator regarding their permit application (Section 3229, PRC).

   The permit application is reviewed by the Division for completeness and to determine whether the proposed plugging and abandonment program is satisfactory. The application must include:
   a. The total depth of the well to be abandoned.
   b. The complete casing record of the well, including plugs.
   c. Such other pertinent data as may be required.

   If the proposed program meets Division requirements, a permit to plug and abandon the well is issued. Division requirements, including what operations the Division will witness, are listed on the permit. The plugging and abandonment operations must begin within one year of receipt or the notice will be cancelled.

The operator is required to submit plugging and abandonment history of all work performed within 60 days of completing required work. The history must describe the work in detail, including volumes of cement used, tops and bottoms of plugs, perforations, junk, locations of cavity shots and perforations used for squeeze-cementing operations, slurry compositions, etc.

Within 10 days after receiving the history of work performed, the Division must issue a final approval of abandonment letter to the operator that includes a statement that cleanup of surface is approved and that all well records have been filed.

If all provisions have not been met, the operator is notified that a final approval of abandonment cannot be issued until the work has been completed properly. A formal order is prepared in cases where the omitted requirements are serious and the operator has not remedied the situation.

4. Is P&A information incorporated into the data management/tracking system? How current is this information and how often are newly P&A wells available in a report?

   Yes. The information is current and available on the Division's web page (WellStat, Weekly Summary, Annual Report, etc.).

5. What is the State's action when an abandoned well is discovered? Please describe the process used to get the well plugged.

   Plugging and abandonment may be ordered whether or not damage is threatened or occurring, Section 3237 or 3755, PRC. Generally, this procedure is used when a well becomes "orphaned". The procedure may also be used as a result of a complaint, or when the District Deputy seeks to plug and abandon a well because it is a threat to the environment or public safety.

   Wells that require formal action fall into two general categories: (a) damaging (Section 3224, PRC) or deserted wells (Section 3237, PRC); and (b) hazardous or idle-deserted wells (Sections 3250-3259, PRC). These wells may be either unbonded or bonded in varying amounts. The procedures for handling these two categories of wells differ slightly and are discussed in the following sections.

   The purpose of an order is to notify all affected parties of the Division's intent to enter a property and plug and abandon a well. As required by the PRC, it is an order to allow entry and abandonment, subject to the right of appeal as specified in Section 3255(c), PRC). Prior informal contact with property owners is made for the purpose of explaining the operations to be performed. This provides better understanding, cooperation, and support from the public in such matters.

If the landowner wishes to dispute the Division's intention to enter the property to plug and abandon a well, the landowner may appeal the order to the Director.

Before a formal order is issued, the following is done:

1. *Every reasonable effort is made to have the operator (if active) comply with our requirements.*
2. *The well is inspected*

Headquarters' permission and review is required prior to issuance of orders to plug and abandon wells. Generally, Headquarters gives the order number to the district office, along with any instructions that Headquarters deems necessary.

Copies of the orders are sent out as follows:

1. *(Original) to owner, operator, or referee in bankruptcy*
2. *Headquarters*
3. *District file (1 to the well record; 1 to the Chronological file of orders).*
4. *Landowner. A cover letter is included to inform the landowner that they have no financial responsibility.*
5. *Surety (if well is bonded). A cover letter is included to inform the surety of the option to arrange to have the work done and that it would be to the surety's financial advantage to do so, as a "cost incurred" charge would be added to the cost of any work arranged by the Division.*
6. *Interested parties (if deemed appropriate by the District Deputy).*
7. *Regional Coastal Commission office if a well is within the Coastal Zone. If extensive road building or vegetation removal is required for access to a well, a Coastal Commission permit may be required. If specific advice regarding the need for a permit is not received from a Regional Coastal Commission office within two weeks, it may be presumed that a permit is not required.*
8. *Local government agency (also inquire as to the existence of a bond). Some local governments require operators to file life-of-the-well bonds. Along with a copy of the formal order, local governments are sent a letter inquiring as to the existence of a bond. If a bond exists, it is pursued as a source of funds to cover the costs of work performed by the Division.*

Copies of all formal orders sent to the surety or operator must be by certified mail, return receipt requested.

6. Does the State maintain an inventory of abandoned wells? Does the State maintain a well plugging fund that is used to plug wells with no responsible party? Describe the nature of the fund, its sources of funding, and any limitations on the use of the fund.

Yes, it's posted on the Division's web page. Where no operator can be located, Division statute currently identifies a $1 million fund for plugging and abandonment contracting.

C. **OBJECTIVE: Understand the Temporary Abandoned (TA) Well Status Program used by the State.**

1. Does your UIC program include a separate formalized (by statute or regulation) administrative program for temporarily abandoned wells and how is a TA well defined. Please provide a summary of the limitations on the Operator once TA status has been approved by the agency for a given well.

   The Division administers an idle-well program that is similar to a temporarily abandoned well program. A major difference is an active well can become idle without Division approval. Because the term temporarily abandoned implies that a well has been disregarded by the operator, the Division uses the term "long-term idle" instead.

   Long-term idle means any well that has not produced oil or natural gas or has not been used for injection for six consecutive months of continuous operation during the last 10 or more years. A long-term idle well does not include an active observation well. Long-term idle wells are categorized as 5, 10, or 15 year-idle wells (the amount of time since last production).

   If an injection well is idle for two or more years, the approval for injection is rescinded. Since idle injection wells are not subject to the normal MIT schedule, by virtue of them being idle, they are subject to the idle-well testing guidelines.

   The object of the idle-well program is to elevate an operator's awareness of its idle-well inventory and to have idle wells that have no apparent future use plugged and abandoned by the responsible party, at no cost to the State. If the operator does not have specific plans for the well or wells, does not respond to Division inquiries, has wells located in unstable terrain, or has junked holes, the wells are ordered plugged and abandoned.

2. Please provide a copy of any regulations or policies on TA wells that your agency has issued in the past five years.

   See Sections 3008 and 3206, PRC.

3. Does the agency require a mechanical integrity test to be run on a TA well before it is reactivated to an injection well?

If the permit to inject has been rescinded because the well was idle for two years and the operator wants to commence injecting again, the Division requires the operator to reapply for a new permit to inject. The new permit will stipulate the MIT requirements.

4. Describe how TA's wells are tracked and whether they are tracked as a part of the active or abandoned well regimes?

   Long-term idle wells are tracked through WellStat.

D. OBJECTIVE: Understand the Data Management System Used in the Plugging and Abandonment Program.

1. When was the data management system currently used first put into operation?

   1977.

2. Is there capability for the Operators and field inspectors to file some or all of the documentation pertaining to well pluggings and abandonments electronically? Describe what electronic communication is available to the regulated community, other state and federal agencies and the public.

   Not yet, but were working on it (see previous comments on ePermit).

3. Is the agency's data management system locally (intramural) conceived or linked with other state databases?

   WellStat is networked so districts and Headquarters have access to the information. In addition, WellStat is posted on the Division web page, thereby, providing access to p&information to other agencies, industry, and the public.

E. Changes and Program or Policy Since 1990

Exclusive of the changes in data management described under Section D., what statutory, regulatory, or policy changes have occurred during the past ten years to address abandonment of wells and financing of orphan wells?

Prior to 1998, long-term idle well bonding requirements would not provide sufficient funds should a long-term idle well be determined to be orphaned and the Division ordered plugging and abandonment.

The 1998 legislation also increased the annual funding amount the DOGGR can spend for the plugging and abandonment of orphaned wells to $1 million for 5 years. Previously, where no operator can be located and the DOGGR had determined a well to be orphaned, statute identifies a $500,000 fund for the DOGGR to access in contracting for the clean up. In 1994, the Legislature approved an increase from $350,000 to $500,000.

Legislation was passed in 1998 that gave operators a set of options to cover the liability its long-term idle wells. First, an operator could take out a $1 million blanket bond to cover all their operations, including idle wells. Second, operators could choose to pay the annual idle well fee, but on an increased scale reflecting relative hazards: for wells idle less than 10 years the fee is $100; for wells idle 10-15 years the fee is $250; and for wells idle for over 15 years, the fee is $500. Third, operators may take out a $5,000 bond for each individual idle well; fourth, operators may establish an escrow account for each idle well that must be worth $5,000 after 10 years (any interest earned in the escrow account will be returned to the operator); and fifth, operators may establish an idle well management plan that requires operators to eliminate a certain percentage of long-term idle wells (10 years or longer) on an annual basis. For purposes of the plan, eliminate means to return to production, plug and abandon (clean-up), or turn that well into an injection or observation well. An operator choosing the Plan would not be subject to any additional idle well fees or bonding requirements. If they failed to meet their annual goals for plan implementation, they would immediately be required to secure idle well bonds or establish an escrow account for the wells.

The Division also increased bonding amounts for active wells by $5,000. Individual well bonds increased to $15,000 for wells less than 5,000 feet in depth; $20,000 for wells between 5,000 and 10,000 feet; and $30,000 for wells in excess of 10,000 feet. The intent with this 1998 change is that plugging and abandoning costs for a well has increased. The previous rates were established in statute in 1976.

The 1998 bill also increased the amount of annual funding the Division could spend for the plugging and abandonment of orphaned wells to $1 million. Previously, where no operator can be located and the Division had determined a well to be orphaned, statute identifies a $500,000 fund for the Division to access in contracting for the clean up. In 1994, the Legislature approved an increase from $350,000 to $500,000.

PART VII: PUBLIC OUTREACH

A. OBJECTIVE: Understand the Public Outreach Mechanisms used by the State

1. How is the public informed about UIC issues and the promulgation of new regulations and amendments to existing regulations?

   Notices for all new and modified injection projects are published in a local newspaper for 3 consecutive days. The laws and regulations regarding UIC are available for review in any district office, on the Division web page, and at most public libraries. If there are significant comments or concerns, then the Division schedules a public hearing. Local governments and operators are notified of changes or additions to Division policy by written notices. General information on the Division's UIC program is available for operators, local and county governments, and the general public through the Division's web page, informational video, and pamphlet.

2. How is the regulated community identified and informed about UIC requirements?

   1. ***Upon submission of injection permits, the Division informs operators of all requirements in the permit.***
   2. ***"Notice to Operators" is sent to all operators operating in the State whenever there is new Division policy.***
   3. ***Changes to Division programs are posted on its web page.***

3. If used, are mailing lists kept up to date? How often do general mailings occur? Are special mailings sent on specific UIC issues? Who do the mailings go to?

   Yes. They are used whenever a special mailing is sent out. Yes, special mailings have been used for UIC; the latest was in 1996 for changes made to the program regarding MIT requirements. Mailings go to all operators.

4. Please indicate any local, regional. Or national interest groups included in the mailing lists?

   IOGCC, GWPC, API, various county governments, and industry organizations.

5. Which of these groups have shown an active interest in UIC issues? Have any groups shown concerns over UIC well completion practices including hydraulic fracturing of the injection zone?

   Local groups and GWPC.

agencies in your Public Outreach activities? Has there been any decrease in interest by other agencies in UIC regulatory activities? Please list and explain changes.

None to all of the above.

PART VIII: REVIEW OF WATER REUSE MANDATES AND POLICIES

This set of general questions is designed to describe the states efforts to use various categories of wastewater including those associated with the oil industry and UIC Class II wells.

1. Does the state have any statutes, regulations or policies mandating or precluding the reuse of wastewater from the following:

   a. Low level chloride (less than 3000 TDS) produced water from oil field operations that could be returned to the surface or ground water regime?

      Division response – no.

   b. Low level chloride water produced from coal bed methane?

      N/A.

2. Which agency in your state would have to give the Operator permission to either reuse water produced under (1) or return it to the environment through wells? Is reuse taking place at the current time? If so, describe.

   If reuse means to use the produced water for domestic purposes, the Division does not regulate this activity.

PART IX: REVIEW OF COAL BED METHANE PROGRAM (If Applicable)

This section is non-applicable to California. There is no coal bed methane production in the State.

A. Statutory Authorities and Regulatory Jurisdictions

1. Please include a copy of all statutes, rulers, regulations, policies and orders applicable to the production of coal bed methane (CBM) and the wastes derived from the production of coal bed methane.